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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Rossin is Man of Year

CHICAGO — Nuclear Safety Analysis Center Director A. David Rossin has been named Electric Industry Man of the Year for 1982.

Readers of Electric Light & Power voted Rossin the honor. Robert A. Lincicome, EL&P editor, said in announcing the award that Rossin was selected for his "untiring support in the development and implementation of nuclear power in the U.S. and for appearing in countless public forums to convey the electric utility industrys' message that nuclear power is economic and adequately safe."

The Award will be presented to Rossin at the All Engineers Dinner at the American Power Conference in Chicago the night of April 26, 1982. The presentation, which will be made by Lincicome, also carries with it a $1000 contribution in the winner's name to be made to the college or university of his choice. Sherwood H. Smith, Jr., chairman and chief executive officer of Carolina Light & Power, Raleigh, N.C., will be the featured dinner speaker.

Rossin is the seventh man to receive the EL&P award. Last year's recipient was Andrew L. Freeman, general manager of the Minnkota Power Cooperative.

Readers of EL&P have chosen A. David Rossin, director of the Nuclear Safety Analysis Center, as the Electric Industry Man of the Year for 1982.

EL&P Interview begins on Page 21

U.S. electric power policy planned; feds mull nationalization

KANSAS CITY, MO—The lamentations of the electric utility industry over its inability to raise needed capital to finance new plant has gone beyond state regulators to catch the ear of Washington bureaucrats who are now thinking the time may be right for a national electricity policy.

"There has never been at the national level a comprehensive policy on electric power," Howard F Perry of the Department of Energy said at a recent meeting dealing with the problems of regulated industries. "It is absolutely striking. There has been a coal policy, there has been a nuclear policy, there has been a gas policy and an oil policy...but there has never been a policy on electric power."

Perry, who is the utility policy advisor at DOE and is in charge of the national electricity policy project, noted that the federal government has never articulated its interest in electricity nor how it would like to see that interest put forward. "It now appears that we are going to do this," he said.

Currently within the federal government are various views on what should be done in addressing a national electricity policy, Perry noted. He said that these views range from a "do-nothing" perspective, move through notions of having the federal government modify state regulations or set up operational guidelines, and come to actually having the federal government usurp state regulatory authority. Regarding the latter, Perry said, "It could be done; it's clearly constitutional. The Congress has expressed no taste for it in the past, but again, it is not entirely out of the question. And there are some advocating (this), even within the industry and within state regulation."

"The circumstances in electricity supply most likely to lead to nationalization," Perry added, "...(are) a massive shortfall of capacity. That kind of thing can bring the monsters out of the woodwork almost overnight.

"It is also striking," he said, "that we are one of the few countries in the world that continues to have a non-state owned electric system."

Federal action: A response

Perry left little doubt that consideration of federal action with regard to electricity was seen to be not an initiative by the U.S. government, but a response to the accumulating problems encountered by the industry. "What may not be obvious," he said, "...is that the need to develop a national policy on electricity is more of a push away from business as usual than it is a pull toward any particular kind of federal policy in the future. It is a reaction to what exists, not a calling for an alternative."

"There are a lot of folks who feel that the problem is the electric utility industry and 'fixing' it may be precisely the wrong thing to do. What we want is electricity, not the electric utility industry the way we know it . . ."

And if the federal government now believes it must weigh action to modify "business as usual," Perry sees a corresponding attitude on the part of the electric utility industry and regulators. Mentioning the White House meeting held in early February in which 15 representatives from utility companies, nuclear vendors, Wall Street and state commissions gathered to discuss with Vice President Bush the status of nuclear power, Perry reported, "The meeting very quickly shifted away from a discussion of nuclear problems toward a discussion of the underlying electric utility problems. And I can report that there is an absolute consensus, that business as usual in the utility industry and in regulation is not going to cut it—that it is going to lead to very substantial problems within 10 years and that somebody at the federal level ought to begin to pay attention to those problems right now before it is too late."

At this White House meeting, Perry said, there were some who advocated certain versions of nationalism but, he added, "Nobody—not a one—recommended business as usual and

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NRC commissioners clash over new safety goals

WASHINGTON, D.C.—The Nuclear Regulatory Commission has issued for comment its proposed policy statement on safety goals for nuclear power plants, and even before the first response has been received disagreements are emerging from within the agency over the relevance of it all.

"Starting with a grand overall safety goal has the appeal of logical neatness, but it is not the way to go about dealing with our needs. . .," Commissioner Victor Gilinsky protested. He noted that what was important in the present reactor licensing climate was to devise specific guidance for dealing with "some very difficult practical questions."

"The most pressing one," he said, "is how to handle 'backfitting,'—that is, to what extent shall new requirements be applied to plants that have already received authorization for construction or operation? As a practical matter, essentially all the decisions the commission will face over the next decade will be of this type."

Proposed policy issued

In its preliminary policy statement the NRC outlined some qualitative safety goals and some provisional numerical guidelines, both of which, when modified by appropriate comment, are supposed to reflect the agency's determination on the acceptable level of risk to public health and safety and on the cost-benefit tradeoffs in regulatory decisionmaking.

In essence, the commission has proposed that *individual* members of the public should not be burdened with any significant additional risk to their health and safety because of nuclear power plants. In addition, it is

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Hope Creek-2 recovery told; PSE&G to stress 'alternatives'

NEWARK, N.J.—Details on how Public Service Electric & Gas will recover its investment in its now-abandoned Hope Creek-2 nuclear plant have been released by the New Jersey Board of Public Utilities here.

While nuclear plant abandonments have become increasingly common in recent months, cancellation of the Hope Creek-2 plant is noteworthy for two reasons. First, it is a plant that is further along in construction than others that have been cancelled recently—over 18 percent. Second, abandonment was initiated by the New Jersey Public Advocate's office and termination was based on a proposed agreement among the utility, the advocate, and the Board of Public Utilities to approve recovery (see *EL&P*, March, 1982, page 3).

Abandonment loss estimated

The projected cancellation loss specified by PSE&G for the Hope Creek-2 plant is $291 million, which includes $190 million for Public Service's 95 percent share of construction expenditures through the end of 1981. (Atlantic City Electric owns the other 5 percent.) More than $47 million is included in the calculation for the cancellation of nuclear fuel contracts, and $33 million for carrying charges on the investment, less $4.8 million in salvage credits. The board has directed the company to explore all opportunities for increasing the salvage credits and said it would review the

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Regulatory ratchet clicks, nukes are abandoned, but Nuclear Regulatory Commission envisions brighter future

Dan Utroska
Associate Editor

Regulatory uncertainty, together with difficulties in raising capital and declining load growth, is nearly always cited when an electric utility decides to cancel a proposed nuclear unit. But when a company abandons a nuclear plant, it is seldom clear precisely what impact the ever-growing federal regulations actually played in the host of factors leading to the termination decision.

There is one group of plants, however, which, because of the post-Three Mile Island ratcheting bind, can legitimately point to special regulations aimed at them. This group consists of those plants that had applied for a construction permit before the TMI accident but had not been granted one by the NRC. The cries of utility managers of these plants are particularly plaintive as they point to these special requirements while announcing abandonment of their nuclear plans.

Referring to these regulations, which originally ensnared 11 plants after the TMI accident, Boston Edison Company president and chief executive officer Francis M. Staszesky asserted at the cancellation of the Pilgrim-2 nuclear unit, "Of particular significance to the Pilgrim-2 project was the requirement that construction permit applicants commit to review certain major facility modifications 2 years after a construction permit is issued. These potential modifications represented significant exposure to redesign, construction retrofits, project delay and increased cost. Therefore, even if we assumed that a construction permit was obtained by April, 1982, we would be proceeding with a project with an uncertain scope, cost, and schedule."

Out of the 11 plants that the Nuclear Regulatory Commission initially identified after the TMI accident as being the objects of tailored regulatory obligations, only five remain publicly committed to construction. From a practical standpoint, there may only be one left and that project is being reevaluated. This group consists of those plants that had applied for a construction permit before the TMI accident but had not yet received it.

Originally, the group consisted of Boston Edison's Pilgrim-2 plant; Portland General Electric Company's Pebble Springs, units 1 and 2; Puget Sound Power & Light's Sakgit units 1 and 2; Duke Power Company's 3-unit Perkins station; Public Service Company of Oklahoma's two-unit Black Fox plants, and the single unit Allens Creek plant now being contemp[illegible] by Houston Lighting and Power Company.

Electric Light & Power has recently reported the cancellations of the Pilgrim, Perkins, and Black Fox units. While the Pebble Springs and Skagit plants remain officially committed to construction, both projects are facing major obstacles to continued progress. "The economic and financial factors would have to improve significantly before we would commence construction," a spokesman for Puget Sound Power & Light said, referring to the Skagit plants. "We would need some assurance that the licensing requirements will remain constant." In addition, a study is currently underway in the region to determine long-term electricity demand. Results of the survey are expected to be issued in about a year. "Construction will not start unless these 3 elements (financing, licensing, and demand) are met," the Puget spokesman explained.

Portland General Electric Company currently believes that its two proposed Pebble Springs plants "are too costly to terminate at this point," and development of the project is, accordingly, proceeding slowly, a utility representative said. Although the post-TMI regulations implemented by the NRC are seen to potentially impact construction of this plant, Portland General Electric finds itself with a lot of nuclear equipment on hand while facing a number of more imminent obstacles to construction. requires the establishment of a feder- These include the state statute which ally licensed nuclear waste repository before any additional nuclear plants can be built in the state. A popular vote in the state permitting nuclear construction is also required, a company spokesman said.

While Portland General Electric may be wondering what to do with over $100 million worth of equipment if the plants are not built (including a nuclear steam supply system, turbine, and other hardware), Houston Lighting and Power Company is trying to locate potential buyers abroad for the nuclear steam supply system it has purchased for its proposed Allens Creek nuclear unit, one of the initial 11 in the post-TMI construction application catagory. It is this plant that the NRC sees as still being a live project.

But in late January the utility announced that it was reevaluating its plan to construct the proposed 1,200 megawatt plant and the company said that it would consider building a coal-fired plant at the site instead. While HL&P spokesman Graham Painter stopped short of saying that Allens Creek was dead, he noted, "We recognize that we do have a lot of problems with licensing—not problems, unknowns." Houston Lighting & Power filed its construction permit application with the NRC in August 1973 when a proposed two-unit plant was estimated to cost about $1.2 billion. Today, with one of those units already scrapped, the other unit alone is expected to cost $2.1 billion. If the utility can find a buyer for the hardware it has for sale, this could expedite abandonment of Allens Creek.

HL&P has two other nuclear units in construction; both units of the South Texas Project are well along in the building process.

New NRC construction regulations

What has hit this category of proposed plants is the series of regulations that were promulgated by the Nuclear Regulatory Commission last year and which became effective February 16, 1982. In essence, the new requirements fall into three classifications. First, a "probabilistic risk assessment" has to be conducted at each plant no later than 2 years after it receives its construction permit. The agency's plan here is to use this relatively new statistical mechanism in order to identify weaknesses in plant designs. While the PRA is viewed as providing more sophisticated methods for designing safety systems, it also threatens excessive backfitting and this is what scared Boston Edison and presumably a number of other utilities that have recently cancelled nuclear plants.

Second, those plants that got caught in the NRC's new licensing net were required to have containment structures that were stronger than those of similar plants already in construction.

Finally, as a result of the Three Mile Island accident, these 11 plants that had applied for a construction permit were required to have more sophisticaed hydrogen control features.

While these requirements, in varying degrees, contributed to the cancellations of numerous nuclear projects recently, the rules have apparently not dissuaded Westinghouse from envisioning completion of its offshore power plant manufacturing facility sometime in the future and thereby keeping its application current with the NRC for a manufacturing license. A manufacturing license is basically a construction permit without a site.

NRC attempts to end ratcheting

Although it is an independent agency, the NRC currently is coordinating its efforts in the regulatory area to harmonize with President Reagan's vision of reducing statutory requirements on industry enterprises. Late last year the agency set up a new department to review generic reactor requirements and to act as kind of a watchdog for regulatory changes proposed by the NRC staff.

"There has got to be some point at which these (new reactor) requirements stop," Dr. Thomas E. Murley, director of the NRC's Regional Operations and Generic Requirements staff said. Murley, who as former director of the Division of Safety Technology largely oversaw the agency's construction permit rule changes that smashed into utility plans to build 11 nuclear plants, is now working to review and restrict nuclear plant modifications proposed by the staff unless they can be shown to be needed.

"We have never really been able to control backfitting and (regulatory) ratcheting," Murley conceded, but notwithstanding this he is hopeful the agency's "final design approval" rules will be able to accomplish this. Such an approach to licensing, which would standardize certain nuclear plant designs so they could be referenced by utilities desiring to build nuclear plants, leads Murley to believe that slowing the rate of new requirements is possible.

"There are no guarantees," he allowed. "There is just the feeling that the level of review and understanding is much higher now than even 5 years ago. This commission appears to be determined to go ahead with a policy on standardization of nuclear plants."

The standardization concept would permit reactor manufacturers to submit to the NRC plant designs that could be used as a "standard" for any utility wanting to construct a plant of that type. If the plant met all applicable requirements, it would be given a final design approval, which, according to Murley, would be held unchanged for up to 10 years, given the absence of some TMI-type event. NRC review of the construction of these plants would be very limited, Murley said, and would be conducted principally to determine that the plant had been built according to specifications. One of the current day phenomena this idea is aimed at eliminating is plant design that is only a few months ahead of construction. This, Murley said, is the case with the South Texas project nuclear plants being built by Houston Lighting and Power.

Standardizing complicated plants

To some industry observers, efforts to standardize complex and crowded nuclear plants is tantamount to institutionalizing a nightmare. The Electric Power Research Institute has recently reported that U.S. nuclear utilities are unhappy with the complexity of these light water reactor plants and the California-based research organization had set out to determine how the plants could be simplified (see *EL&P*, June, 1981, page 1).

But earlier this year, EPRI decided that it would "redirect" this research effort, putting its present effort into

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Editorial

Extended nuclear fuel burnup program cut would cost U.S. dearly

Federal budget and tax cuts are long overdue. Unfortunately, in the rush to hold deficits down, increase defense appropriations and still fund popular social programs, a number of small, little-publicized but still highly beneficial programs will be eliminated or, at best, extensively whittled down.

One in this latter category is the Department of Energy's extended nuclear fuel burnup program, a 6-year old effort designed to develop a reactor fuel that will release two-thirds more energy than current fuels. Slated to be completed by 1988, the extended burnup program, according to DOE and confirmed by the General Accounting Office, could produce savings for users of electricity of $12 billion by the end of the century, resulting in a benefit-to-cost ratio of 385:1.

Benefits include the prospect of reducing total nuclear generation costs by 2.5 percent, slashing spent fuel production by 40 percent and reducing the waste storage requirement. Fuel cycle costs could be cut 10 percent and potential worker exposure to radiation reduced, supporters of the program insist. With higher plutonium content per spent fuel rod, the extended burnup fuel could reduce plutonium recovery costs by some 17 percent, cut breeder startup fuel inventories and increase breeder conversion rates up to 5 percent, according to Combustion Engineering's Dr. N.L. Shapiro.

The budget request for the extended fuel burnup program for next year was $15 million, a tiny amount by government standards. But the Office of Management and Budget would cut this by $3 million.

OMB also would reduce the development program to a single fuel design where eight or more have been under development in the past. Since there are two basic types of reactors — pressurized water reactors and boiling water reactors, each of which needs its own type of fuel — and as many as five different vendors' fuel designs, a single fuel development program would be almost useless. Moreover, reducing the extended fuel burnup program to development of a single fuel design would quickly end U.S. world-leadership in that area, probably the last area of world leadership left to U.S. nuclear system suppliers.

The prospects of the program being carried on by fuel vendors are virtually nil. Fuel vendors already are suffering from demand declines. And with almost three-fourths of fuel requirements for the next 25 years already under-contract, the incentive to develop a fuel that lasts longer is minimal. Most nuclear utilities, forced to pass through to customers any fuel savings, yet finance such a fuel-use improvement from money that costs more than the utility can earn on it, won't pick up the tab. And EPRI, despite high interest, is limited by post-TMI safety and reliability requirements and is currently budgeted for $2.5 million, probably a limit for the next few years.

In other words, if the U.S. is to have an extended nuclear fuel burnup program, it appears the funds must come from government. But in the highly politicized process of budgeting in Washington, the bigger the program budget the greater its importance. Recognizing this, it is easy to see why OMB believes it can safely slash $12 million from the DOE budget. But if Congressional committees allow such a budget curtailment, we shall lose far more than we'll save, even in the short-term.

Robert A. Lincicome
Editor-in-Chief

DOE: Utility industry's financial curbs don't mean energy shortages thru '95

WASHINGTON, D.C. — Even with certain financial constraints, electric utilities will be able to satisfy customer requirements up to 1995 with acceptable levels of reliability if additional gas turbines are built to meet peak demand, a government study has concluded.

The research, conducted by the Energy Department's Energy Information Administration, also found that the financial contraints could actually provide some short term financial benefits.

"Lower capital expenditures would reduce utilities' requirements to secure investment funds at high interest rates and would reduce the pressure for higher electricity prices in the immediate future," the report said. It was noted, however, that electric companies would have to continue to make minimum capital expenditures to complete new construction already underway, perform maintenance, and conduct general operations. "Thus," the report concluded, "deterioration of common stock prices and book values and of the general financial condition of the industry could continue regardless of reduced absolute levels of capital expenditures."

The report is called "Impacts of Financial Constraints on the Electric Utility Industry," and was prepared by the EIA's Office of Coal, Nuclear, Electric, and Alternate Fuels.

Two cases examined

The report investigated two hypothetical cases, one in which capital spending was relatively unrestrained and another where financial constraints were imposed. The Edison Electric Institute has calculated that $338 billion will be needed during the rest of the 1980s for new plant construction and as can be seen from the table, the Energy Information Administration, estimating a comparable figure for a slightly longer time period — 1979 through 1990 — has reported $389 billion (in 1980 dollars) for its unconstrained—or base—case.

The estimate of financial constraint is seen by the reduction, of nearly 29 percent, from the estimated funding available in the base case in 1990. Overall conclusions are based on projections of 3.2 percent growth in demand over the period.

In addition to the longer-range negative effects on utilities under financial contraints, the EIA determined that continued financial pressure on the industry would not allow most utilities to make optimal economic decisions to expand generating capacity or to replace existing oil-fired and gas-fired power plants. This restriction, in turn, is said to be capable of producing a number of serious adverse effects on the industry in the long run.

First, the EIA found that the failure to build "more efficient" coal and nuclear plants would mean foregoing an opportunity to eliminate about 82 percent of current oil and gas use by utilities. The results of this were seen to be higher fuel costs and attendant distortions for fuel consumption in other sectors of the economy. In addition, the report said, this use of oil could cause the continuation of U.S. dependence on imports.

Unfortunately, the statistical rationale underlying DOE's findings that the failure to build "more efficient" coal and nuclear plants would have serious negative impacts later on are not included in the present report. Queried about the absence of oil supply, demand and price data in the analysis, one DOE analyst involved with preparation of the report said, "Not including it was an oversight. It had been in the first draft."

The oil supply, demand, and price data, it was explained, were taken from an earlier report sent to Congress by DOE. In essence, oil prices

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Air basin plan revised and relaxed

NEW CASTLE, PA — Appoval of a revision in the Upper Beaver Valley Air Basin Plan has eliminated the need for millions of dollars of scrubbers at Pennsylvania Power Company's New Castle Power Plant.

The plan approved by the Environmental Protection Agency, allows a slightly relaxed sulfer dioxide emission limit of "no more than 2.8lbs. SO_2 per million BTUs on a 30-day running average basis."

Penn Power had estimated that scrubbers would cost $85 million and approximately $14 million to operate annually.

Revised limits

Under the appproved revision, the same SO_2 emission limit that applies to the Allentown, Johnstown, Reading, and Erie air basins now also applies to the upper basin. Previously, the limit that regulated the upper basin area was the same as that used for downtown Pittsburgh.

COMPARISON OF CUMULATIVE UTILITY CAPITAL EXPENDITURES—BASE CASE VERSUS FINANCIAL CONSTRAINTS CASE (BILLIONS OF 1980 DOLLARS)

	1985		1990	
Category	Base Case	Financial Constraints Case	Base Case	Financial Constraints Case
Coal	48.4	23.4	131.8	58.4
Nuclear	63.1	55.1	86.0	61.9
Transmission and distribution	65.0	65.0	116.3	116.0
Other	23.5	20.0	55.1	41.1
Total	200.0	163.5	389.2	277.4

Note: Data represent estimates of cumulative capital expenditures from 1979 through each of the milestone years. Expenditures for power plants and facilities under construction on or before 1990 and scheduled for operation after 1990 are included in the tables.

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Nuclear too costly ...

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per kilowatt and $4,400 per kilowatt. This is to be contrasted to the capital required to build coal units, which came in between $2,168 per kilowatt and $2,506 per kilowatt.

While a spokesman for Public Service Company of Oklahoma generally verified the calculations on levelized busbar costs reported by the OCC, the company was more vigorous in stressing the political and regulatory atmosphere in which it saw itself operating. "These are what really killed the project," Vaughan Conrad, manager of stategic programs development said.

However, utility figures on costs per installed kilowatt, while essentially within the ranges set by PSO, tended to be at the upper edges of these ranges. For two nuclear plants that would come on-line in 1993 and 1995, the cash construction costs were estimated to be $4,472 per installed kilowatt, and for the corresponding three coal plants expected to come into operation in 1991 and 1994, the cash construction costs were set at $2,090.

Fossil plant ordering blitz

While the two Black Fox nuclear units were part of the 5,811 MW of nuclear capacity cancelled during 1981, according to figures released by the Atomic Industrial Forum, during the same period electric utilities ordered 7,500 MW of new fossil-fired stationary electrical utility generating units, according to figures compiled by the American Boiler Manufacturers Association.

Fossil plant orders last year, up 47 percent over 1980, reflect more megawatts ordered than in any year since 1977. This suggests that, rather than there being a general decline in all orders for new plants, nuclear units are being substituted by fossil plants.

According to Russel Mosher of the ABMA, there were no fossil-fuel generation plant cancellations during the past 2 years.

The ABMA said, however, that it did not have a breakdown as to how many magawatts of the ordered 7,500 MW were coal plants, nor did it know the average size of the plants ordered, nor which utilities had signed contracts with fossil plant vendors.

FCC launches inquiry

WASHINGTON, D.C. — An inquiry to determine the best strategy for meeting the future needs of private land mobile radio users, such as utilities, has been launched by the Federal Communications Commission.

Commission officials say an inquiry is necessary because of the tremendous growth of private land mobile radio which, if continued at the projected rate, could result in a serious frequency congestion problem.

The inquiry has been broken into two major areas; the first is to deal with anticipated private and mobile requirements, and the second with possible sources of spectrum to meet those requirements.

Financial curbs . . .

from page 4

were assumed to rise to $37/barrel in 1985; to $41/barrel in 1990; and to $50/barrel in 1995.

Power plant capital requirements were determined by data supplied to DOE from electric utilities. Estimates that were received from the utilities on what plants they expected to build and operate in the future were part of the modelling used in the present report.

Another adverse effect that the EIA envisioned as a result of financial restraint was an increase in consumer costs by 1995. Using the April 1981 DOE study "The National Electric Reliability Study" to buttress its conclusions, the agency declared clearly that "Even though the relatively unrestrained building allowed in the base case (see table) would entail substantial capital outlays and produce reserves far beyond those required for system reliability, the resulting savings in operating costs could produce lower rates for electricity in the long run."

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THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

'Rate shock' crisis faces completed nukes

Dan Utroska
Associate Editor

It used to be that if electric company managers endured all the intervenor and regulatory delays, all the federally mandated design modifications, and the financial stress attendent upon building a nuclear power plant, then efforts would finally pay off as the plant became licensed and was put into rate base.

It could reasonably be expected that the higher capital costs of the nuclear plant would essentially be offset by fuel savings.

Today, if a nuclear plant makes it through all the federal construction and licensing reviews, it now faces a new difficulty: the growing political reluctance of public utility commissions to grant full rate base treatment for large base-load generating plants.

Alabama Power Company's Farley-2 unit is the first plant in recent time to be given a zero rate order after that plant went into service. In addition, both Long Island Lighting Company (with respect to its Shoreham plant) and Pennsylvania Power & Light (with respect to its Susquehanna Plant) are actively exploring alternatives to conventional rate base treatment. Philadelphia Electric Company's Limerick plants and Houston Lighting & Power's South Texas Project plants also have been mentioned as possibly coming in for less than full rate base treatment when they become operational. Assuredly, there will be others.

The impact of zero or partial rate base treatment by public utility commissions for large new plants around the country, caused by growing consumer resistence to higher electric bills, could be devastating. Electric companies with large construction programs are likely to be among those utilities in the shakiest financial condition; not being able to fully recover a large investment in new plant (or being able to recoup only some percentage of this), could knock the support out from under these companies.

Such state regulatory decisions therefore will be watched closely. Moreover, these negative rate orders carry potentially significant meaning for utility managers who are pondering the feasibility of continuing nuclear or other large base-load projects already in progress. Even under historical assumptions that full rate base treatment would be granted at or near in-service dates, utilities that have been constructing nuclear units have nevertheless been experiencing touch-and-go economics. Such calculations have already nudged out the

Continued on page 16

Tests confirm new breeder core design

IDAHO FALLS, IDAHO — The analytical methods used to redesign the reactor core of the proposed Clinch River breeder reactor are valid and the core will perform as intended, tests reportedly have confirmed.

The experiments were conducted at the Energy Department's Zero Power Plutonium Reactor (ZPPR), located at the Idaho National Engineering Laboratory here.

Originally, the core designed for CRBR — the socalled homogeneous core — contained plutonium-bearing fuel assemblies scurrounded by a blanket of uranium-bearing assemblies. The ZPPR experiments are said to have confirmed that the new core design — referred to as the heterogeneous core — could breed nuclear fuel with greater efficiency, improved operating safety, and reduced reactor fuel and control system costs (by an estimated $8 million).

The new "heterogeneous" core uses a different configuration of fuel elements than the "homogeneous" core. Also, some of the blanket assemblies in the new core are dispersed among the fuel assemblies.

"The results of these tests place this country in the forefront of breeder core design, and, as such, are key developments in the progress of the Clinch River project," DOE Assistant Secretary for Nuclear Energy Shelby T. Brewer said.

The assistant secretary noted that the experiments have confirmed that not only does the new core outperform previous designs, but it will operate with greater efficiency than even foreign designs.

The Clinch River plant is to be built in Oak Ridge, Tennessee, and is the nation's first large-scale demonstration liquid metal fast breeder reactor power plant. When operational, it will generate 375 megawatts, enough electricity to meet the residential needs of a city of 200,000.

The Clinch River breeder reactor project is the cooperative effort of the Department of Energy, the Breeder Reactor Corporation, and a number of electric utilities around the country.

Biggest solar field completed

Some of the more than 1500 solar collectors installed at Georgia Power Company's new general office building in Atlanta are shown. The installation, made up of more than 1.5 acres of trough-shaped, glass-covered panels, is the largest commercial application of solar collectors for space and water heating in the U.S. For a report on the current status of utilities' large-scale solar projects, see page 34. Photo: Richard Riley, Tampa, FL.

Power equipment demand to grow slower to '90, NEMA finds

WASHINGTON, D.C. — The need for generation and transmission and distribution equipment, while it will continue to grow over the next 2 decades, will do so at a declining rate, a new industry survey shows.

The "Eighth Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry, 1981-1990," reveals a greater deceleration of the growth of electricity demand and supply than has been shown either in previous biennial surveys or by other examinations of power industry requirements.

"There can be no doubt about the direction and the permanency of the alterations to the electricity industry in the U.S.," the introduction to the current survey reads. "The nation will carry on its functions and expansions using less electricity than heretofore thought possible. The price of electricity, the conservation ethic, and load management techniques have and will continue to slow the growth of the demand for electricity."

The biennial surveys are sponsored and published by the Power Equipment Division of the National Electrical Manufacturers Association.

Demand: 3 percent or less

The survey found that in 1982 electricity demand would increase 3.3 percent and would grow by an additional 3.5 percent in 1983. In the longer term, it was determined that de-

Continued on page 6

Nuclear utilities financial review dropped by NRC

WASHINGTON, D.C. — Declaring that there is no demonstrable link between the financial condition of a nuclear utility and the health and safety of the public, the U.S. Nuclear Regulatory Commission has decided to drop its requirement that electric companies planning to build nuclear power plants must be financially viable.

Before the March 30, 1982 amendments to NRC regulations, which eliminate financial reviews by the agency, an applicant for a nuclear construction or operating license had to show either that it had sufficient funds, or that there was a reasonable assurance that such funds could be secured, to cover applicable regulatory requirements. For construction permit applicants this meant that sufficient funds had to be present to cover construction costs and related fuel cycle costs. For operating license applicants, it meant enough money to cover estimated costs of operating the facility plus costs of permanent shutdown and maintenance in a safe condition.

"Any consideration of decommissioning funding should be eliminated from the present licensing process," a statement from the commission announcing the changes reads. "This does not discount the importance of decommissioning but places it in the context of an ongoing rulemaking proceeding. The NRC is expected to

Continued on page 6

Foreign Power Briefs

• **Korea Electric Power Corp.** has announced plans to build a medium-sized nuclear fuel fabrication plant within the next few years. Officials of the company said that invitations for overseas bids will be made late this year. Korea Electric hopes to complete the facility by the late 1980's. A government corporation, South Korea Electric is the sole power generator in Korea. Plans call for a plant capable of processing about 2,220 tons of enriched uranium annually. Currently, one nuclear plant is operating in the country and eight more are being built. Thirteen nuclear power plants are planned to be on-line before 1991.

• **Saudi Arabia** has signed a $25.9 million contract to buy three gas turbine-generator packages from General Electric Co., U.S.A. for the Jibal Fifa region near the Red Sea. When the units go into operation, scheduled for February 1983, the Saudi Consolidated Electricity Company for the Southern Region will assume ownership and operation. Each of the units will produce 27.47 MW.

• **The UK government** announced they have decided against testing the feasibility of burying radioactive waste in about 20 sites from Ayrshire and Galloway in Scotland to Worcesterhire. A government committee report that said the longer waste is stored, the more safely it can be buried, prompted the decision.

• **The first stage of a Soviet solar power station** that will be built near the village of Mysovoye in the Crimea will be commissioned in 1983. It will include a 75m high tower and a field of 400 automatically controlled concave mirrors. Full capacity of the station will be 5 MW from 1,600 mirrors. A pilot project with three moveable mirrors manufactured by the Ministry of Power Engineering of the USSR will be tried out first to prove the system. The station will have high capacity hot water and steam storage to keep the station operating in bad weather and at night.

C-E Studsvik has received a contract from Statens Vattenfallsverk, the Swedish State Power Board, to supply a compact nuclear simulator representing Forsmark 3, a 1050 MWe boiling water reactor. Reactor and turbine components, including an extraction steam system, heater drains, a suppression chamber and a moisture separator/reheater will be represented. The simulator will also have the capability to display the axial power distribution of any individual fuel channel disturbed by an adjacent control rod. The unit is scheduled to be delivered later this year.

• **Swaziland,** an African state between South Africa and Mozambique, is going ahead with plans for a controversial 20 MW hydroelectric power plant on the Lushuswana River. The dam, on the river, will cut the amount of power bought from South Africa to about half of the present level. Opponents of the project point out that it will also decrease the downstream flow of the river to less than 10 percent of its present volume, thus affecting the ecology of the area. Critics are also calling for the government to take advantage of its substantial coal reserves and build a coal-fired plant. The Swaziland Electricity Board has turned the suggestion down because it says the costs would be too high and the ecological impact on the area would be greater than the proposed hydro plant.

• **Enel, the Italian national electric utility,** expects to be the largest single consumer of coal on the international market, according to its Chairman, Francesco Corbellini. He told a London audience that delays in Italy's nuclear power program forced Enel to build coal-fired plants. Enel has helped a few small Kentucky coal producers organize a consortium to ensure a sales outlet. American coal delivered to Italy is about 35-50 percent cheaper than imported oil. Corbellini also called the plan to build coal-fired plants "transitional and contigent: this means that it is not expected to be followed by new coal programs in the '90s."

• **Japan's nuclear power plant construction program** will be revived this year. After a long stall, Chubu Electric Power Co. starts building its third reactor with 1,100 MW at Hamaika in March. Construction plans totalling more than 4,000 MW , are expected to be approved by the government's Electric Power Source Coordination Council. Largest plans are for two 1,180 MW plants from Kushu Electric Power Co..

• **The first discovery of geothermal steam in Canada** has prompted more drilling at British Columbia Hydro's Meager Creek geothermal site. A first well, drilled to 3,040m, found steam and temperatures higher than 200 degrees Celcius. Such temperatures, if combined with an adequate supply of pressure and water, could produce steam for generating electricity.

• **Jordan's fourth power project work begins** next year, following an agreement between a delegation from the Kuwait Fund for Arab Economic Development, the Jordan Electricity Authority and the Jordan Electric Power Company. Included in the project are plans for a 132 kV transmission network, rural electrification in the North and South of Jordan, and the installation of six new substations

• **Mexico** has turned into a revolving door for world leaders, as they try to win the competition to build $2 billion worth of nuclear reactors in Mexico. Among those visiting Mexican President Jose Lopez Portillo have been Canadian Prime Minister Pierre Trudeau, the King and Queen of Sweden and U.S. Commerce Secretary Malcom Baldrige. Combustion Engineering, General Electric and Westinghouse are after the contract, as well as companies in Sweden, Canada, France and West Germany. Formal bids to build the two 1,200 MW reactors at Laguna Verde were submitted last month. Mexico's Federal Electricity Commission is currently wading through the mounds of documentation. Although Mexico would like to make a decision by August, the presidential elections this summer might delay it to after the December inauguration.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

PG&E hires Bechtel for Diablo Canyon

SAN FRANCISCO — Bechtel Power Corporation has been hired by Pacific Gas & Electric Company to act as project manager for the completion and licensing of the Diablo Canyon nuclear plant.

According to PG&E chairman Frederick W. Mielke, Jr., Bechtel will be responsible for having the company's low-power operating license restored for operation of unit 1. The NRC had granted the company such a license on September 21, 1981, but suspended it in mid-November when problems were discovered in the reactors' construction design. Bechtel is also charged with securing a full power license for the plant.

In addition, the consulting firm will oversee construction of unit 2, which, as of December 31, 1981, was about 90 percent complete. The firm will also provide start-up engineering and construction support needed to bring both units into commercial operation.

Diablo to 'stabilize' bills

The announcement by PG&E that it had hired Bechtel follows a decision by the staff of the Nuclear Regulatory Commission to approve Teledyne Corporation to conduct the design verification program for Diablo Canyon. Mielke said he was pleased with the decision because "the reverification program now can go forward with a minimum of delay."

Mielke added that he shares customers' concern about the burden of this winter's high utility bills. "Getting the Diablo Canyon power plant safely and successfully on line will do more than any single thing the company can do to help stabilize electric bills, minimize our dependence on costly oil and natural gas, and provide our customers with a safe, reliable electric energy supply for the years to come," he said.

Hand delivery saves

CHARLOTTE, NC — Officials of Duke Power Company estimate they are saving more than $7,000 per month from the use of hand delivery of monthly bills.

The company currently is hand-delivering bills in seven cities. The bills are hung on doors because postal regulations prohibit use of mail boxes for other than U.S. mail.

The cost of hand-delivery works out to $0.11 each. The cost of presorted U.S. mail is $0.17 each.

Duke uses high school and college students to deliver the bills because of their eagerness and interest in only part-time work. If they prefer, customers can still receive their bills by U.S. mail.

Duke began a pilot hand-delivery program in 1976. The pilot program showed that hand-delivery was only economic in densely populated urban areas.

Utilities employ innovative strategies to satisfy future power demands

Uncertainties today as to whether to emphasize "fundamental problems," or to highlight financial indicators that are trending upward, characterize the internal conflict of an industry that feels its traditional infrastructure creaking under the strains of new financial realities. The seriousness of the industry's concerns, therefore, is more a matter of focus and perspective than of objective consensus.

Dan Utroska
Associate Editor

The demand upon electric utilities to supply reasonably priced, reliable energy is not only causing companies to identify innovative financing techniques to build traditional base load generating plants, but is prompting some companies to rethink the entire traditional approach to providing electricity.

Given an estimated aggregate financial requirement on the electric utility industry of $338 billion during the 1980s to construct new plant, investment banking firms are scrutinizing the implications of new tax laws, hoping to come up with innovative financing approaches like the debt-equity swap method developed by Solomon Brothers (see box) which permits an electric company to retire bonds, issue new stock, and improve its debt-equity ratio, while sending a healthy chunk of fresh income directly to the bottom line on the company's financial statement.

In other cases, investment houses not only are joining the utility chorus for greater rates of return, higher revenues, and inclusion of construction work in progress in the rate base, but are arguing the necessity of reduced load growth, higher pricing mechanisms, and avoidance of nuclear power.

Additionally, financial analysts are beginning to comtemplate how the electric utility industry, moved by financial constraints, will be forced to change over the next 10 years. "With the industry in poor financial condition, many utility managements and boards of directors, (in order to) protect investors, may seriously question undertaking the capital and operating risks of adding new generating capacity," Daniel Scotto of Standard & Poors Corp. remarked recently before the Financial Analysts Federation Bond Seminar in New York. "This could lead to a host of new financial structures and generic issues to be addressed over the next decade."

Scotto, who is an assistant vice president for electric and water utility ratings, reflected a sentiment at the meeting which seems again to be ascendent: that future capacity additions may not be under state jurisdictions. "Instead," he said, "the production of electricity could be moved to the federal level, under wholesale corporate structures, or even, completely deregulated. Given the current rulemaking hearings on construction work in progress by the Federal Energy Regulatory Commission, prospects for better returns may actually be greater at the federal level."

For their part, certain electric utilities, — and especially those that face capacity additions in the future — are opting for solutions that substantially revamp the more conventional ideas of having the electric company be the central station supplier of power. Arkansas Power & Light Company, for example, is contemplating becoming the main developer, owner, and operator of cogeneration facilities that will produce steam for its industrial customers while creatively providing electricity for its regular service area. The utility envisions that it will be able to back out of electricity production appreciably while doubling its revenues by 1985.

And in a separate action, AP&L, in coordination with the Alliance to Save Energy, is looking into the feasibility of becoming a third party financier of energy conservation in its service territory. Other utilities across the nation are carefully eyeing deveiopments here to see if they have merit.

Utility-industry partnerships

If some electric companies had not already begun to redefine their roles as suppliers of electricity, industrial customers, who also appear increasingly worried about utility construction financing difficulties, are now openly advocating new initiatives, such as corporate compacts in electricity generation.

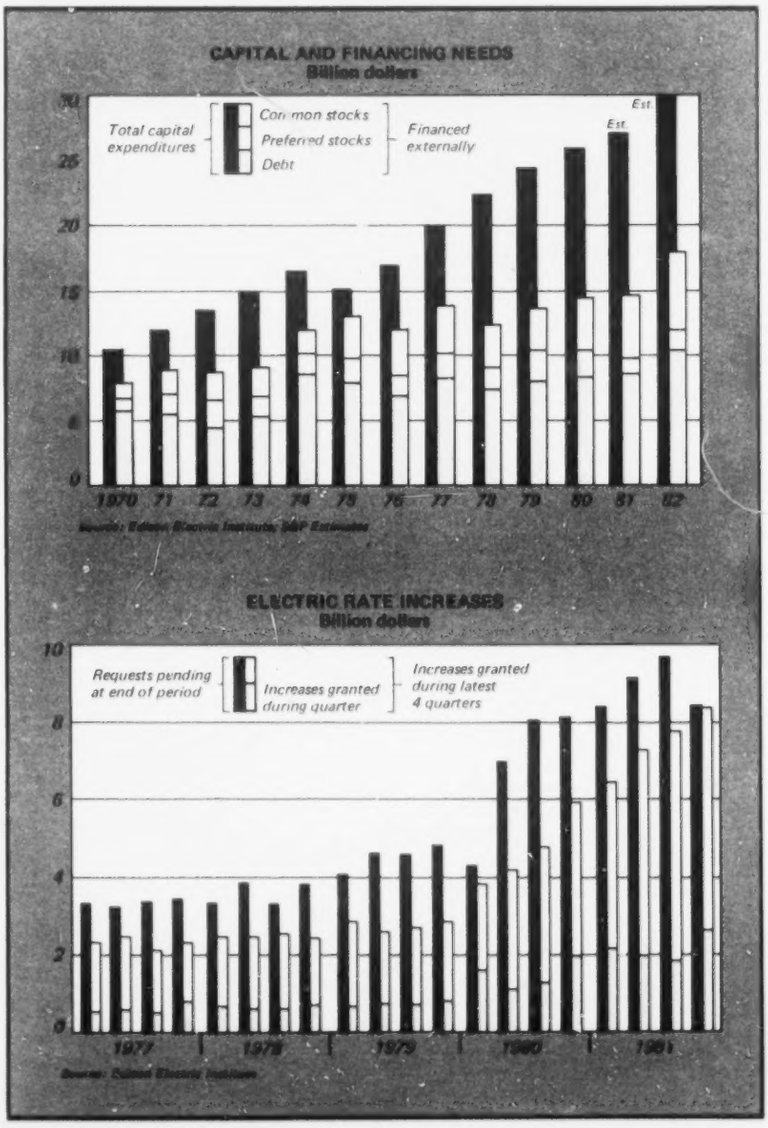
Industrialists, who see themselves as involuntary subsidizers of electricity to residential and commercial users, believe that not only are these "payment transfers" approaching a limit, but higher rates to all classes of customers are rapidly reaching a political boundary. If the rate of recent utility revenue increases dampens, industrialists fear that capital-strapped electric companies, responding to reduced construction programs, will be forced to discourage new demand.

In a move at self-survival, some industrialists therefore are calling for the serious consideration of power partnerships. "There is little else left to try but to solve the problems together by forming financial alliances between utilities and industry," Herbert J. Edwards, senior vice president of Ebasco Business Consulting Co. said.

Noting that conventional financing and pricing of generation tends to "frontload" the cost to the ratepayer, (because kilowatt-hour costs increase precipitously as the plant is included in rate base), Edwards said that alternatives would levelize these costs over time. "This means that the economics of self-generation, as well as cogeneration, may be turning around. Compared to the uncertain availability of power, even at new-resource costs, industrial investments in power supply will be more economic as time goes by," he said.

The success of such corporate compacts depends upon the parties identifying innovative financing techniques as well as new technologies. Also, many traditional barriers have to be overcome. "If these barriers cannot be surmounted," Edwards said, "utilities face not only a declining industrial sales base and lower efficiencies; they face obstacles to economic development of their service areas as well."

He concluded, "Should it come to pass that industrial firms are forced by circumstances to provide their own power, keep in mind that timing is vital. In today's world it takes 10 years to get a major generating unit built. In 10 years we could all learn Japanese like a mother tongue."



Financial "problem": how severe?

What seems most to characterize discussions about the financial condition of the electric utility industry is the gaping disparity of views over whether there is or is not a crisis — or even a problem. "There are a whole lot of serious people who say there is no problem at all," Howard F. Perry, Utility Policy Advisor at the Department of Energy said. "There are a lot of other serious people who say the electric system is going to hell in a handbasket."

Perry, as head of DOE's national electric policy project, will, over the next few months, attempt to find out where the truth lies. "Sorting this out is not an easy task, but we are going to try to do it this year." (see EL&P, April, 1982, page 1).

In addition, the National Association of Regulatory Utility Commissioners is in the process of writing a report on its findings regarding the financial condition of the electric utility industry. Originally expected to be completed for the association's annual meeting in November, 1981, release of the report is now targeted for sometime in July, 1982.

According to Standard & Poors' Kenneth M. Alterman, although average *authorized* returns have increased from 12.5 percent in the early 1970s to 15.5 percent in 1981, recent *earned* returns on equity have been only in the area of 11 percent. This compares with 12 percent in 1970. In

Duke Power reaps benefits from debt-equity swap

Duke Power Company appears to be one of a growing number of businesses that are turning to the debt-equity swap to retire discount debt, while issuing new shares of stock, and improving the quality of earnings.

This innovative financing method, if it is properly structured, can result in a transaction that is tax free, and although the technique reportedly is still without an actual tax ruling by the Internal Revenue Service, it is being given the go-ahead by numerous corporate attorneys.

In essence, an investment banking firm ventures into the market to buy up a company's existing low-coupon bonds, sometimes offering a price slightly over market to induce sales. Acting as a principle in the transaction, the investment banking firm now calculates how many shares of a company's stock will be required to offset the retired debt plus various costs that arise from the deal.

The investment banking firm now swaps the retired debt with the company for the new stock issues which the banking firm then turns around and sells on the open market. The principle benefit to the corporation is that it is able to send directly to earnings the difference between the face value of the retired securities and the cost the company paid for them. The company is therefore able to avoid the taxes it would have had to pay if it retired its outstanding debt on its own.

The principle features of the Duke Power transaction are outlined in the table. Of paramount interest here is the tax free gain of $48.3 million that was realized by the utility. The swap deal was concluded during the first week of January, 1982.

According to Duke Power's William H. Grigg, the swap increased the company's common equity component of capital structure from 39 to 41 percent, while long-term debt declined from 48 to 46 percent.

Further, the effective book value of the newly issued shares was

"When it comes to raising new equity capital in the marketplace without equity dilution, this may be the only game in town."

$32.68, 137 percent of the 1981 year-end book value. Grigg, who as senior vice president at Duke deals with legal and financial matters, said this resulted from the fact that no shares were issued on the incremental gain that resulted from the swap and which is entered on the books as equity.

The benefits that accrue to the company are a stronger capital structure which reduces the financial risk of all of the company's securities. This makes new debt and common equity capital more readily available at lower cost than would otherwise be the case.

In addition, common equity is increased without the dilutive effect of selling new shares at prices below book value. This is expected to result in higher earnings per share and fewer dividend payments in the future. A corresponding improvement in cash flow is also seen.

Finally, the tax-free nature of the exchange provides new capital at far less cost than if capital were raised through retained earnings, where income taxes take about one-half of earnings.

For all its advantages, the debt-equity swap does not affect the company's need to raise new capital. Because no cash is involved in the exchange, the company's future capital requirements remain the same. "Recapitalization is what this is," Grigg said.

There are some potentially negative impacts here. First, the swap has no immediate effect on rates. However, the stronger capital structure that results from the swap can be interpreted as requiring lower allowed return on equity because of the reduced financial risk. "Our analysis showed that, in fact, some reduction in allowed return on equity can be made without taking away all of the earnings per share benefit of the exchange," Grigg said. "The risk is that the allowed rate of return might be reduced below the 'break-even' point for the cost of service, thereby penalizing the equity investor."

Grigg said that Duke believed that taking such a risk was reasonable. "The alternative," he said, "was either a certain further decline in fixed-charges coverages or a certain further dilution of shareholders equity through the sale of common shares at prices well below value."

Another risk encountered when a regulated company engages in such a debt-equity swap relates to how the gain is accounted for. Grigg said that unless the gain is recognized as an extraordinary item of income and carried to retained earnings, the benefits of the transaction are lost. "In Duke Power's case, that risk was minimized by obtaining prior approval of our regulatory authorities of the proposed accounting treatment."

"In short, this swap made good business sense to us and we were willing to accept the rate of return risk," Grigg concluded. "Clearly, it may not fit the needs of every utility...and it requires careful analysis. But when it comes to raising new equity capital in the market place without dilution, it may be the only game in town."

DUKE POWER COMPANY DEBT-EQUITY SWAP

	(in millions)
Debt retired (first mortgage bonds)	$119.9 face amount
Average coupon of bonds retired	8%
Average market price of bonds	58.9% of face amount
Gain on bonds (carrying value less market price)	$ 48.3
New common shares issued	3.7
Market value of shares ($20.375 per share less $.66 underwriter's discount)	$ 73.5
New common equity (market value of shares issued plus gain on bonds)	$121.8
Book value of new shares	$ 32.68 per share (137% of book value per share at 12/31/81)
Change in Book Value	from $23.83 to $24.19 per share

Change in Capital Structure:	Before	After
L/T Debt	48%	46%
Preferred	13%	13%
Common	39%	41%
	100%	100%

Embedded Cost of Debt:		
	At 12/31/81	9.34%
	Effect of Exchange	.06
	As Adjusted	9.40%

1974, Alterman said, the spread between average authorized and earned returns on equity was 190 basis points; currently it is more than 300 basis points.

In addition, while earned returns on equity have remained virtually unchanged during the decade, he said the quality of earnings has deteriorated noticeably. Also, allowance for funds used during construction (AFUDC), as a percentage of net income, is currently near 50 percent, contrasted to 12 percent in 1970.

"This growth in the portion of non-cash earnings reflects the quantam rise in the cost of new generating capacity, extended delays in construction, escalating costs of capital, and the growing percentage of funds invested in non-revenue producing construction work in progress," Alterman said.

Twelve years ago, he said, the average electric utility was rated "AA." Today, the industry's "center of gravity" is "A-," and is trending toward "BBB+."

And according to the Edison Electric Institute, the inadequacy of equity returns is underscored by the gap that exists between these returns and the cost of new debt. Using 1980 figures (the most recent available from EEI), new long-term debt was issued at interest rates averaging nearly 14 percent. Comparing this to a 1980 earned return on equity of 11.4 percent reveals a negative risk premium of 2.6 percent. This negative risk premium was realized, EEI said, while the equity markets were demanding just the opposite — a 3 to 4 percent premium return differential over long-term interest rates.

Despite some recent positive signs, "there are still fundamental problems for the electrics," Alterman concluded.

Yet, uncertainties today over whether to emphasize these "fundamental problems," or to highlight financial indicators that are trending upward, characterize the internal conflict of an industry that feels its traditional infrastructure creaking under the strains of new financial realities. The seriousness of the industry's concerns, therefore, is more a matter of focus and perspective than of objective consensus.

Some healthy signs

"For the first time since the electric utility industry's financial interlude during 1976-78, things are looking up," S & P's Daniel Scotto said. He noted that many equity analysts are pointing to higher allowed returns on equity, more cash flow from the 1981 tax act, completion of major construction projects, especially nuclear, and declining spending and less reliance on common stock financing.

Yet, Scotto said, "The industry is far from being out of the woods financially. When an industry is flat on its back, things are generally looking up."

The Edison Electric Institute, on the other hand, regularly concentrates its focus on the more threatening aspects of the future. "If the electric power industry falters, the nations economy falters as well," EEI's president William McCollam Jr., told the New York Society of Security Analysts recently. "The industry's less-than-robust financial health puts its ability to provide that power at risk ....If we are unable to complete construction schedules for vitally needed plants, it will not be long, perhaps later in this decade, most certainly early in the next, when electric power shortages can be expected to constrain the economy, with resulting adverse effects on employment, on the U.S. ability to compete in the world markets, and on the national security."

And in testimony late last year before a financial status inquiry committee of the National Association of Regulatory Utility Commissioners, H. L. Culbreath, chief executive officer at Tampa Electric Co., representing Edison Electric Institute member companies, referenced the institute's calculated negative risk premium. "This negative return will not be accepted on a continuing basis," he testified. "At some point equity investors will respond by investing less in utility securities."

Utility stock sales brisk

Not only has a recent Department of Energy report challenged assertions that financial constraints on power plant construction are likely to lead to power shortages through the 1990s, (see EL&P, April 1982, page 4), but electric utility stocks out-performed the overall market by a wide margin in 1981. In addition, the data show that utility stocks have held up extremely well in the early months of 1982, doing so under generally poor market conditions.

"For the first time in many years, the Standard & Poors index of electric utility stocks in 1981 was a better performer than the S&P 500 index," S&P's business magazine The Outlook reported in early March.

"The electric utility index posted a gain of 7.9 percent and ranked 33 out of 110 S&P stock groups, while the '500' declined nearly 10 percent. In terms of total returns (price change plus dividends), the performance disparity is even greater. The total return of the electric utility index amounted to 21 percent, versus a negative 4.8 percent return for the '500'."

The Outlook also concluded, "The price gains have been recorded despite an uptrend in interest rates."

There may be components within this healthy total utility stock return

Continued on 10

Future power demands ... from previous page

that appear stronger than they actually are, however. S&P reports that in many cases of utility operations, earnings did not justify corresponding dividend boosts. "As a result, the average payout ratio (dividends as a percentage of earnings) has risen to levels not seen since the early 1950s," The Outlook reports. "The ratio for 1981 approximated (the) 1980s' 74.6 percent, up from 67 percent 5 years ago; the peak of 78.6 percent was reached in 1951. The ratio could edge higher this year (1982), with dividends rising slightly more than the 5 percent increase in earnings we (at S&P) are estimating."

Whether these "pumped up" dividend components of total returns are sufficiently inflated to constitute a future liability for electric companies, and whether this practice is sufficiently wide-spread in the industry to appreciably undercut recent measured advances in total returns, is at present unclear.

Electric utility optimism

While various industry observors are examining earned returns on equity over the past year or so and shaking their heads in despair, J. H. Ranniger, a vice president at Public Service Company of Colorado, has taken heart from such recent advances in electric utility fina..cial indicators. In fact, Ranniger sees such a confluence of positive economic, regulatory, and corporate factors that he felt moved to stand before industry colleagues recently and declare, "That ball of fire on the horizon which some viewed as the setting sun for the utility industry can now be viewed as the sunrise, not the sunset."

And, he added, "This is a time for optimism. The darkest hours are behind us."

Challenging figures presented by others, Ranniger said that in 1981 the return on equity earned by the electric utility industry had advanced toward the 12.5 percent level. He noted, "There is still a long way to go, but the trend is in the right direction." The PSCo executive said that many of the difficulties that had arisen in the 1970s, were beginning to be resolved and further remedies were being identified that would work to strengthen the industry in the 1980s.

Ranniger mentioned reduced regulatory lag time, the increase in authorized rates of return, the fact that some 23 jurisdictions, including the Federal Energy Regulatory Commission, now use some form of forecasted test years for the calculation of rates, and that some 20 percent of the regulatory jurisdictions now specifically incorporate an attrition allowance into their revenue calculations.

He observed that authorized revenue increases have been "greatly increasing" in recent times, and that in 1981 dollars aggregate revenues have gone from $2 billion in 1971 to $7.7 billion in 1981. "In the same 10 year period, the ratio of revenue increases granted to that requested bottomed out in 1976 when only 51.5 percent of that sought was granted. That ratio has increased to an estimated 69.1 percent for 1981," he said.

The market-to-book price ratio of utility stocks also has shown marked improvement in recent months, Ranniger observed. He noted that the ratio has improved from 75 percent in January, 1981, to an estimated 81 percent in December, 1981. "Again," he noted, "there is a long way to go, but...this trend is in the right direction."

With respect to rate base treatment, Ranniger's research found that 22 state jurisdictions and the District of Columbia use year-end rate base, whereas some years ago, average rate base was in much more widespread use.

He noted that most electric companies have undertaken stringent cost control programs and have launched educational initiatives to put their respective cases before regulators, the federal government, and the public.

Finally, the increasing use of cost-based rate design is seen to inherently provide not only equitable treatment of all customers, but the reshaping of utility load characteristics so as to minimize overall costs of rendering service. "It can," Ranniger said, "provide for the charging of customers who create undue cost burdens on the company, and can...provide for the minimization of the construction of very expensive new generating facilities."

Alternative approaches weighed

Very expensive new generating facilities is one of the prime reasons underlying the growing attention being paid by electric utilities to cogeneration. "In light of the economic and tax motivations for cogeneration and the impetus provided by the Public Utility Regulatory Policies Act of 1978, the movement towards cogeneration is gaining momentum and substance," said Kenneth F. Seplow, vice president of Kidder, Peabody, & Co. Speaking at the recent Energy Technology Conference in Washington, Seplow noted that electric company responses have varied from reluctant, mandated participation to positive and aggressive action, such as that exhibited by Arkansas Power & Light.

"Though the reactions differ across the country, most electric utilities are coming to terms with PURPA, and by extension, cogeneration," Seplow said. He noted that the displacement by cogeneration of 10 percent of today's industrial electric usage has been calculated to require $15 to $30 billion of capital, depending on the methods employed. Seplow cited various economic reasons why industrial companies, although unlike electric utilities in many respects, have been generally disinclined to retrofit to cogeneration facilities. But he noted that newly constructed industrial facilities have been incorporating cogeneration. Although these projects tend to be small and relatively few — "only a trickle now," he said,—the trend is here. "It could readily grow into a stream which in a decade could produce the $15-$30 billion of aggregate capital investment mentioned earlier as a possible benchmark."

"Cogeneration is a new diversified business in which existing energy enterprises can build on old strengths — knowledge of markets and energy economies and mechanics," Seplow concluded. "Investment in cogeneration can be a good capital investment. It affords debt leverage and tax advantages. It has some of the stability of the electric utility business without the same kind of adverse regulation. In effect, under PURPA, it benefits from regulation of the electric industry, but permits the investor to operate without a declining rate base or a rate of return limitation."

Utility as third party financier

Third party financing of conservation is another alternative approach to financing new base-load construction and here, as in cogeneration, Arkansas Power & Light is emerging as an industry pacesetter. Selected by the Alliance to Save Energy to investigate the feasibility of a major utility assisting its customers with energy conservation investments, AP&L, in coordination with the Alliance, is looking at some 20 standard industrial code (SIC) catagories in its service area to determine the nature of these potential commercial and industrial investments, and the expected payback over a specified time period.

When the Alliance to Save Energy received a grant of $428,000 from a large private foundation to examine this question, it began scouting around to determine which utility might be most enthusiastic about actually implementing load reduction methods in its service area. After reviewing numerous electric companies, the Alliance settled on AP&L. "We were persuaded that AP&L was truly committed to energy conservation," Robert J. Rauch, an attorney and legal consultant for the Alliance said.

There are 3 major types of the third-party financing of energy conservation: leasing, share-the-savings plans, and energy service contracts. Each has advantages and disadvantages for different types of energy users and presents a different set of tax and legal risks for the third-party investor.

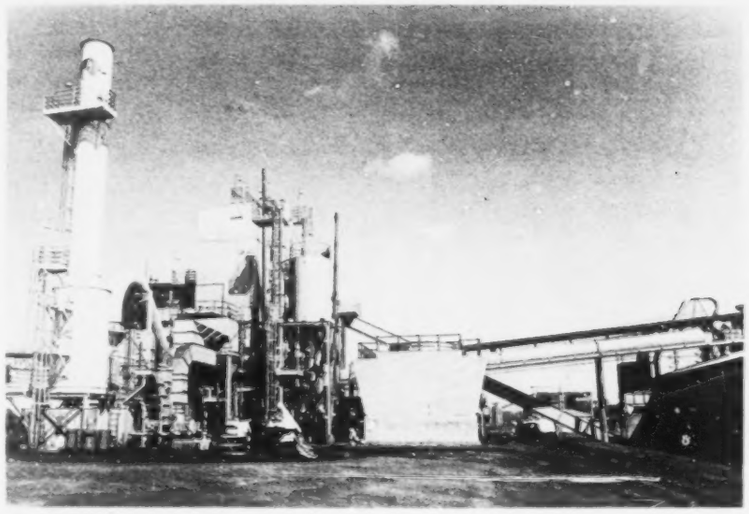
And in addition to utilities getting directly involved in financing, there are other important roles they can play, some of them in participation with private investors. An electric company might provide low-interest loans to private groups that are trying to put together third-party financing of conservation strategies. This could aid those groups that are able to put certain equity money up front but have to borrow the rest to get going.

Also, certain electric utilities could form a financial pool for insurance purposes. Such a pool, Rauch explained, could act as an economic safety net for those energy conservation enterprises that fall short of projected goals. Even with professional engineering analyses of specific energy conservation projects, potential investors might be skittish about the ultimate realization of estimated energy savings. With electric companys' underwriting possible shortfalls, investor participation in these enterprises could be enhanced substantially.

"We think that utilities' participation potentially is very important because third-party financing of conservation will make up a sizeable portion of the total conservation during the 1980s," Rauch said.

Described as the first in-depth study conducted to assist commercial and industrial customers with energy conservation, the AP&L/Alliance project has stimulated the interest of numerous electric companies. Participants in the study say they hope the findings of the research effort, which are expected to be released sometime in November, 1982, will have an influential impact on those utilities that currently believe encouraging conservation is not an electric company function.

Almond nutshells fuel new power plant near Sacramento



This 8,500 kW power plant fueled by almond shells delivered 1.9 million kilowatthours of electricity to Pacific Gas and Electric Company in its first month of operation. Imotek, Inc., a San Francisco engineering firm, owns and operates the plant, which is located at the California Almond Growers Exchange near Sacramento.

SACRAMENTO, CA — A new cogeneration plant fueled by almond nutshells has delivered 1.9 million kilowatthours to Pacific Gas and Electric Company in its first full month of operation.

Located at the California Almond Growers Exchange, the plant is owned and operated by Imotek, Inc., a San Francisco engineering firm. In addition to producing electricity, the plant produces steam for use by the almond growers' processing facility and by a neighboring industrial plant.

Malcom A. MacKillop, PG&E senoir vice-president said that the utility is committed to renewable resources. "Last year," he said, "we increased our commitment and now plan to have almost 60 percent of our new generation capacity in the 1980s come from these resources."

Projects total 884,523 kW

Since its cogeneration program began in 1980, PG&E has negotiated power purchase contracts or other firm commitments for projects that will total 884,523 kW in generating capacity when they are complete.

Of PG&E's contracts, cogeneration and solid waste projects account for 409,800 kW; wind farm projects, 382,800 kW; small hydro power plants, 81,300 kW; and miscellaneous projects the remainder.

PCB elimination cost set at $10-20 billion

WASHINGTON — It could cost the electric utility industry from $10 billion to $20 billion to completely get rid of PCBs, according to a report recently submitted to the Environmental Protection Agency by the Edison Electric Institute. An EPA-supplied summary of the EEI report suggests that current EPA regulations on PCB-containing equipment be left largely unchanged.

The EEI report is part of a review of PCB regulations ordered last year by the District of Columbia U.S. Court of Appeals. The court ordered the review in response to a suit brought by an environmentalist group, the Environmental Defense Fund, challenging EPA's treatment of utility PCB equipment. EPA regulations currently define such equipment as an acceptable "totally enclosed" use of PCBs and set the regulatory cutoff at material contaminated with 50 ppm or more of PCBs. The appellate court said that EPA's justification for these definitions was insufficient and ordered it to issue new regulations by this coming August based on better supporting studies. The EEI report is to constitute part of the improved backup material for the new regulations.

An EPA spokesman says the EEI report, submitted in late February, was a big step toward getting out the new proposal, which should be published in the Federal Register about now. (The proposal was due in April, the final regulation in August.)

EEI's analysis of the cost of replacing all equipment contaminated with more than 50 ppm PCBs is shown in the tables. The raw costs are shown in the first table and the incremental costs in the second. The incremental costs are the actual additional costs that would be imposed on utilities by a requirement to phase out PCB equipment over various time periods. These are less than the costs shown in the first table because some of this equipment would be phased out and replaced in the normal course of events.

The report says that out of the total of 24 million pieces of equipment in the utility industry, 22.1 percent contain fluid with more than 50 ppm PCBs, and 12.8 percent have fluid with more than 500 ppm. Askarel transformers and PCB capacitors account for 93 percent of the equipment in the greater-than-500-ppm category.

Enough capacity

EEI cites estimates from the National Electrical Manufacturers Association that there is sufficient manufacturing capacity to replace askarel transformers in service with "low flammability" substitutes in about 5 years. "Such production estimates," says the report summary, "are based upon the assumption that utilities would be willing to accept currently available low flammability technology as a replacement for askarels, and would also make whatever changes are necessary in system engineering or equipment siting to accommodate the increased risk of fire."

For PCB capacitors, EEI estimates that the capacitor manufacturers could replace all utility-owned PCB units now in service with acceptable substitutes in 8.4 years, if production capacity were increased 50 percent. However, there are many PCB capacitors outside the utility industry, EEI notes, and a nationwide replacement program would take considerably longer.

It would take about 3 years to replace all the contaminated mineral oil equipment in service, says the report. Transformer manufacturers are currently turning out approximately 1.3 million units a year, at 60 percent of production capacity, says EEI. Replacement oil could also be supplied in about the same time frame.

Disposal facilities for contaminated materials could be a problem though, the report warns. If the two currently licensed incinerators did nothing but burn askarel from utility-owned transformers 20 hours a day, 350 days a year it would take 5.3 years to get rid of it all, says EEI. Everybody's askarel would take 17.6 years. Mineral oil from utility transformers containing more than 500 ppm PCBs would take 3.4 years, according to the EEI analysis. The report notes that some "destruction" processes have been approved by EPA, but adds, "Since these processes have received only preliminary approval to operate, it is impossible to determine the commercial scale costs of these processes or the ability of these processes to significantly impact the time required to dispose of PCB-contaminated oil.

Only one incinerator is licensed to burn shredded capacitors, the report notes, and it would take it 19 years to handle existing utility-owned PCB units. If the second unit is licensed, the job could be done in 4.1 years.

The two incinerators would require 12.5 years to burn the 730 lb of contaminated mineral oil in utility-owned equipment. The report concedes that oil with less than 500 ppm can be burned in utility boilers, but it says that use of this option is limited: "Despite the relatively low conversion costs (one utility recently completed conversion for approximately $72,000) required to prepare a utility boiler for incineration, only 6 utilities of the 100 largest utilities sampled are currently doing so, and they indicate no intention of offering this service to other utilities....Overall strong public resistance has severely restrained the use of this disposal alternative."

As mentioned, the total cost of indentifying PCB equipment, replacing it, removing the old equipment, beefing up fire protection capability, storing PCB materials, and disposing of the PCBs is estimated by EEI to be in the $10 billion range.

As an alternative to complete replacement, equipment could be rinsed with a solvent to get contamination below 50 ppm and refilled with clean fluid. That option, says EEI, would cost $8.7 billion.

Another regulatory option would be to require inspection and containment of potential spills from utility PCB equipment, in the form of dikes, retention ponds, etc. EEI's analysis of the costs associated with this option are shown in the third table.

The EEI report also analyzes the leak potential from utility PCB and PCB-contaminated equipment, as shown in the fourth table. Leak rates and amounts were extrapolated from PCB spill reports stemming from the interim measures program put into effect after the appellate court ruling last year.

As shown in the table, askarel transformers and PCB capacitors account for 99.75 percent of the PCBs that may be leaked, using the upper bound numbers. "The remaining annual PCB losses (0.25 percent) from mineral oil equipment," says the report summary, "are likely to be leaked in extremely small quantities (average leak quantities range from less than one one-hundredth of one tablespoon to one-tenth of one tablespoon; the median volume of mineral oil leaked or spilled is less than one gallon, of which 0.06 ounces are PCBs.)"

Regulatory action aimed at preventing leaks or spills of mineral oil with more than 500 ppm PCBs would only prevent a total of 230 lb of PCB from entering the environment every year, says the report. Prevention of leaks from oil with 50-500 ppm would only eliminate 508 pounds per year of PCBs.

SUMMARY OF EQUIPMENT PHASE-OUT COSTS
(In 1981 Pre-Tax Dollars)

Cost factor	Askarel transformers	Mineral oil transformers containing ≥500 ppm PCBs	PCB capacitors	Mineral oil equipment containing 50-499 ppm PCBs
Identification[a]	–	$6,100,000,000	–	$ 6,400,000,000
Equipment replacement	$ 552,000,000	190,000,000	$ 806,000,000	2,660,900,000
Removal/ installation	495,000,000	108,000,000	381,000,000	1,083,300,000
Disposal[b]	169,000,000	160,000,000	260,000,000	478,000,000
Total	$1,216,000,000	$6,558,000,000	$1,447,000,000	$10,622,200,000

a. If testing were not done or if all mineral oil equipment were required to be taken out of service, the replacement, removal/installation, and disposal costs would increase by a factor of 10.
b. Does not include costs of interim storage.

INCREMENTAL COSTS OF 2, 5, 10, AND 20 YEAR EQUIPMENT PHASE-OUT COSTS
(In 1981 After Tax Dollars)

Phase-out period	Askarel transformers	Mineral oil transformers containing ≥500 ppm PCBs	PCB capacitors	Mineral oil equipment containing 50-499 ppm PCBs
2 Years	$832,000,000	$3,100,000,000	$968,000,000	$5,900,000,000
5 Years	736,000,000	2,900,000,000	830,000,000	5,500,000,000
10 Years	590,000,000	2,700,000,000	622,000,000	4,800,000,000
20 Years	346,000,000	2,300,000,000	277,000,000	3,600,000,000

ESTIMATED CONTAINMENT COSTS FOR PCB PROGRAMS TO CONTAIN SELECTED PCB-CONTAMINATED MINERAL OIL EQUIPMENT
($ Billions)

Type of equipment	Identification costs	Dike construction costs	Water accumulation costs[b] Bi-weekly inspection	Weekly inspection	Retention ponds/ tanks	Total cost
Pad-mounted PCB-contaminated mineral equipment	$1.4	$1.0	$2.4	$4.8	$1.3	$3.7-$7.2
All pad-mounted PCB-contaminated mineral oil equipment and 75% of PCB-contaminated pole-mounted mineral oil equipment[a]	$6.4	$2.3	$9.2	$18.4	$5.0	$13.7-$27.1

a. Assumes that 25% of pole-mounted units are located in areas which cannot be diked.
b. Assumes inspections for the estimated 20 year remaining useful life of the equipment.

ESTIMATED TOTAL POUNDS OF PCBs LEAKED/SPILLED PER YEAR AND AVERAGE LEAK QUANTITY BY EQUIPMENT TYPE

Equipment	Total PCBs leaked/spilled per year (lbs)	Average quantity of PCBs leaked/spilled per leak/spill (lbs)
Askarel transformers[a]	178.9 - 20,448.0	0.55 - 64.5
PCB capacitors	43,159.2 - 369,251.0	2.0 - 17.1
Mineral oil transformers	7.2 - 825.7	0.00004 - 0.005
Voltage regulators	0.15 - 4.9	0.0001 - 0.004
Oil-filled circuit breakers	0.04 - 50.9	0.000002 - 0.003
Reclosers[b]	0.002 - 6.6	0.0000001 - 0.0004
Switches (e.g., sectionalizers)[b]	0.051 - 79.7	0.000001 - 0.0019
Total	43,345.5 - 390,666.8	

a. Assumes moderate leakage rates equal to mineral oil transformers.
b. Assumes moderate leakage rates equal to highest rate in equipment surveyed (i.e., oil filled circuit breakers).

TVPPA study shows auxiliary drives for hydraulic aerial devices save fuel, $

CHATTANOOGA, TN — Auxiliary drives for aerial devices — gas-, diesel-, propane-, or battery-powered — can save money and fuel for utilities, compared to using the vehicle's engine to drive a hydraulic pump through a Power Take Off (PTO). But, concludes a new study conducted for the Tennessee Valley Public Power Association (TVPPA), the extent of the savings is dependent on type of vehicle, extent of usage, and the locale where the vehicle is used.

The study, which was conducted for TVPPA by Lupton Engineering Associates, Inc., Chattanooga, focused on the different types of auxiliary drives available, their advantages and disadvantages and the types of usage for which each was best suited. Factors considered included the impact of specific truck fuel, truck usage (city or rural), and vehicle type (service, line or tree-trimming).

PAYBACK PERIODS
(No refueling savings—years to repay cost of auxiliary drive)

	Auxiliary Drive Type							
	Electric		Gasoline		Propane		Diesel	
Type of truck	Aux. cost	Payback	Aux. cost	Payback	Aux. cost	Payback	Aux. cost	Payback
Gasoline fueled								
Service-city & rural	–	–	$2500	>15.00 yr	–	–	–	–
Line-city	$9000	10.52 yr	2500	6.63 yr	$3900	5.00 yr	$6800	7.67 yr
Line-rural	$9000	>15.00 yr	2500	>15.00 yr	3900	>15.00 yr	6800	>15.00 yr
Tree-trim, city	9800	6.15 yr	2500	5.31 yr	3900	>15.00 yr	6800	5.85 yr
Tree-trim, rural	9800	>15.00 yr	2500	2.70 yr	3900	>15.00 yr	6800	9.22 yr
Propane-fueled								
Service-city & rural	–	–	similar to paybacks for gasoline trucks above		2900	>15.00 yr	similar to paybacks for gasoline trucks above	
Line-city	9000	>15.00 yr			2900	>15.00 yr		
Line-rural	9000	>15.00 yr			2900	>15.00 yr		
Tree-trim, city	9800	>15.00 yr			2900	>15.00 yr		
Tree-trim, rural	9000	>15.00 yr			2900	>15.00 yr		
Diesel-fueled								
Service-city & rural	–	–	–	–	–	–	–	–
Line-city	9000	>15.00 yr	2500	>15.00 yr	–	–	6800	>15.00 yr
Line-rural	–	–	–	–	–	–	6800	>15.00 yr
Tree-trim, city	9800	>15.00 yr	2500	>15.00 yr	–	–	6800	>15.00 yr
Tree-trim, rural	9800	>15.00 yr	–	–	–	–	6800	>15.00 yr

Data in unshaded areas, indicates economic viability. Payback periods were calculated on a discounted life-cycle cost technique with fuel cost escalation. Discount rate was 10 percent. Fuel escalation was calculated on 3 percent more than the discount rate for 3 years, 5 percent more than the discount rate thereafter.

Conclusions

The study report listed the following results and conclusions:

- All types of auxiliary drives can save some fuel and reduce direct operating expenses when installed on line trucks or tree-trimming vehicles.
- Auxiliary drives offer the greatest payback when used on trucks fueled with gasoline and propane.
- Electric auxiliary drive's greatest advantages are quiet operation and elimination of exhaust fumes in the work area.
- Gasoline engine auxiliary drives' greatest advantage is their low first cost, which provides an excellent payback.
- Diesel engine auxiliary drives' greatest advantages are long engine life and very low fuel consumption.
- Electric auxiliary drives work better on aerial lifts with closed center hydraulic systems than on those with open center systems.
- Auxiliary drives *do not* offer significant fuel or operating cost savings when used on service type trucks.
- Auxiliary drives *are not* cost effective for bucket trucks that use less than six (6) gallons of fuel per day in non-road use.
- Auxiliary drives used on diesel-fueled trucks do not provide any substantial additional savings over those significant operating cost reductions obtained by diesel fuel use itself.

The rationale behind the study was that a bucket-truck operator does not need the power of a 200 hp or greater truck engine to operate a 10 hp hydraulic pump. Also, pump operation is intermittent, not constant, and therefore does not require constant motor idling.

Use of auxiliary power units to drive the hydraulic pump provides sufficient power, as needed, with much lower energy consumption than a truck engine. Moreover, less wear on the engine for pump operation contributes to longer trouble-free primary engine use to power the truck itself.

Auxiliary drives' benefits

Auxiliary drives offer four primary benefits to users. A major advantage is reduced fuel consumption. This means an immediate reduction in operating costs. A corollary to this is that with reduced consumption, more trucks could be kept in-service should there be a future fuel shortage. Engine wear also is reduced, often for periods up to 4 hours. This extends the time between oil changes, tune-ups, engine overhaul and rebuilding, and significantly increases the time of use before replacement. As a result, the study points out, truck reliability is improved and maintenance expenses are reduced.

Reduced engine use also decreases the time during the day required for refueling.

Since the auxiliary drive system is not designed to totally replace the PTO; but only to replace its use for powering the small hydraulic pump, a truck equipped with both has increased reliability in the field.

One major drawback to use of auxiliary drives is that during cold weather the cab of the truck will be cold. If the engine is used, the cab will be heated and work crews can periodically warm themselves.

Another disadvantage is that while the auxiliary drive is operating, the truck's battery system is called on to operate the radio, lights and supply power for the auxiliary drive control system. Since the battery is not being charged all day, as it would be if the truck were operated in the PTO mode, increased battery maintenance can be anticipated.

The auxiliary drive systems also require a capitol investment before any savings can occur. Payback can be several years.

The additional weight of the auxiliary drive equipment, especially with battery pack electric system, reduces available payload that the truck might otherwise carry.

And finally, addition of an auxiliary drive system means added maintenance.

Equipment

The auxiliary drive system can be either electrically-powered, from a separate battery system, or fuel-powered with gasoline, propane or diesel oil. If fuel powered, the report says, it's most economic to select an auxiliary drive that uses the same fuel as the truck itself.

New load management program allows customers to choose level of service

WASHINGTON, D.C. — Just like purchasing a car based on quality and price, a customer of Southern California Edison Company can now buy electricity according to the level of service he wants.

According to Geoffrey R. Bales of Edison, Demand Subscription Service (DSS) is the first major attempt by an electric utility to utilize a remotely-activated residential load management device that allows the customer to select his level of service. Bales recently presented the DSS program at the 9th Energy Technology Conference & Exposition.

After a customer decides to have DSS installed, a customer service representative is sent to evaluate the customer's use of power. An in-depth load check of all the appliances is done and the representative explains the impact of the different service levels that the customer can choose. A lock on the DSS prevents tampering with the load-limit switch. If the device is disturbed, an indicator light will alert the meter reader to the problem.

Eight signal towers located in metropolitan areas of Edison's service territory send out signals that activate the units. Although other approaches, such as powerline carriers, are being explored, Bales explained that signals are currently sent over VHF-FM radio waves. A computer console in Edison's general office building activates the DSS during a system capacity shortage.

When a customer exceeds the previously selected load-limit, signals from the towers will start an alert device. The device has three colored lights and an audio signal to inform the customer of the DSS status. A green light indicates that there is a system capacity shortage and that the unit has been put into operation. If the customer uses 75 percent or more of his predetermined service, a yellow warning light flashes. And if the customer exceeds his level, a red light flashes along with a continuous beeping noise for 1 minute. During that minute, the customer must reduce his load or service is temporarily cut off. Service can be restored by reducing load and pressing a button.

The load management device is easily installed between the electric meter and the user's panel. During the initial experimental stage in 1980 and 1981, the units were built to Edison's specifications using off-the-shelf components.

Since the level of service selected is only a constraint during system capacity shortages, Bales said the utility initially expected customers to respond favorably to the program.

More than 2,500 units were installed and Bales said reaction was very good. Customers were able to decide whether to use the air conditioner, electric water heater or any other mix of appliances. Edison also offered customers a reduction on their monthly bills if they participated in the experiment.

Initial testing indicated a peak load reduction of approximately 3 MW and gave Edison officials strong promise for the program. Bales said the DSS program proved to be cost effective when compared to the expenses involved with building and operating combustion peaking power plants.

An aggressive DSS plan is scheduled for the near future. By the end of 1984, Edison hopes to have 110,000 units installed throughout its service area. The company also estimates the peak load reduction will equal about 140 MW once the program is fully in place.

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Officials chide industry for lack of TMI action

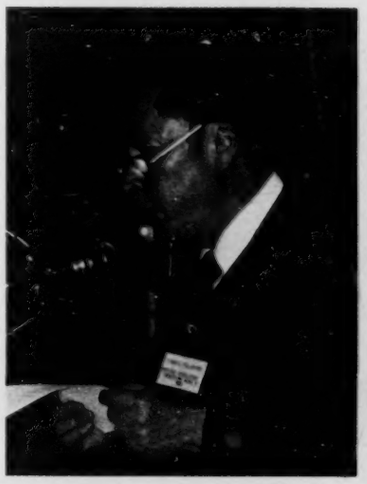
ST. CHARLES, IL — Calling the pace of cleanup activity at the TMI accident site "disturbingly slow," Nuclear Regulatory Commission chief Nunzio Palladino said he wants the nuclear industry to take action. Speaking at the same conference here, which was sponsored by McGraw-Hill Co.'s nuclear industry newsletters, White House science advisor John Marcum said he found it "unusual" that nuclear utilities have not yet provided the $190 million pledged to TMI cleanup by EEI.

Palladino said he is worried that GPU's insurance money, now being used for the cleanup, is going to run out. He called TMI an unstable situation well on its way to becoming a "serious" situation. He said the longer industry waits the longer the scar of TMI will remain. "I do not hear the voice of the nuclear industry," on TMI cleanup, added the NRC head.

White House advisor Marcum, who is assistant director for energy and natural resources in the Office of Science Technology and Policy, said that the federal government has taken the initiative in providing TMI cleanup funds via the $125 million promised for R&D aspects of the cleanup. The time has come for the utility industry to put up its share, said Marcum. The money is available, he claimed, noting that four times as much as the money pledged to cleanup has been sent to EPRI.

Both Marcum and Palladino called on the industry to improve post-TMI operations. Marcum noted that there are still major unsolved operating problems such as steam generator tube failures and pressure vessel embrittlement. He also said that the financial risk to nuclear utilities remained "intolerable" since a program of full insurance coverage for another TMI-type accident has not yet been obtained.

Palladino also felt that utilities should continue to upgrade efforts to absorb lessons learned from TMI. He was particularly concerned that utilities continue to strengthen their quality assurance programs.



NRC chairman Nunzio Palladino on the lack of outside help for the TMI cleanup problem: "If the industry doesn't see that it has an enormous stake in a satisfactory conclusion to that momentous accident, then perhaps there is less hope for expeditious removal of this scar from the back of the industry than I thought."

PUCs move to halt Pebble Springs, Limerick nukes

BARRINGTON, IL — The public utility commissions in Oregon and Pennsylvania, concluding that continued construction of nuclear projects in their states is not in the best interest of ratepayers, have stepped in to oppose building the plants.

While state agency intervention is different in the cases of Portland General Electric's proposed two-unit Pebble Springs plant and Pennsylvania Electric's Limerick plant, both manifest what appears to be a growing inclination on the part of commissions to take the initiative in deferring or cancelling nuclear projects.

Earlier this year Public Service Electric & Gas Company entered into a negotiated settlement with the NJ Public Advocate's Office and Board of Public Utilities with respect to Hope Creek-2. The company cancelled the plant on the basis that it would be allowed to recover substantial portions of its investment in the enterprise (see *EL&P*, March, 1982, page 3; and April, 1982, page 1).

In early May, the PA PUC, reading the sentiment of the state legislature, decided that it would not grant Philadelphia Electric's request to include some $500 million of construction work in progress (CWIP) in the rate base for the company's two Limerick nuclear plants. This action, in turn, led the agency to conclude that without such financial help, it would be impossible for PE to continue building the two nuclear units on its current schedule. Rather than risk another slippage, the PUC decided to do what it could to nudge Philadelphia Electric into suspending construction on unit 2 while concentrating its efforts and resources on unit 1.

Both Limerick units are nominally 1,055 megawatts, and as of December 31, 1981, unit 1 was about 70 percent complete and unit 2 about 30 percent complete. Target completion dates for the two plants are 1985 and 1987.

According to a PUC motion drafted by commission chairman Susan Shanaman, an analysis of Limerick construction in light of the CWIP request denial showed that completion of unit 2 by 1987 was "not financially feasible." While the majority of the commissioners agreed, they felt they did not have the legal authority to order outright that Philadelphia Electric cancel unit 2. The commission de-

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Justice Dept. seeks to block Initiative 394

WASHINGTON, D.C. — The U.S. Department of Justice, at the urging of the Department of Energy, has filed suit challenging the constitutionality of Initiative 394 passed by Washington State voters late last year.

The referendum, passed on November 3, 1981, in effect requires the Washington Public Power Supply System to secure voter approval before it can sell any bonds to finance its on-going nuclear construction program. Currently, the supply system has three plants in construction, all of them well along in construction. It had been estimated that about $3.7 billion in additional financing would be necessary to complete WNP-1, WNP-2, and WNP-3. The initiative is to become effective July 1, 1982.

The announced deferral of WNP-1 is expected to reduce construction expenditures somewhat (see story, this issue).

The thrust of the Justice Department's complaint is that the initiative, if allowed to stand, essentially subverts not only the agreements that exist between the supply system and the Bonneville Power Administration (which is to market the power

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NARUC group forms first diversification 'rules'

Dan Utroska
Associate Editor

MADISON, WI — In a second floor hotel conference room here, down the street from the grand state capitol building, five state regulators met late one evening in May to discuss the regulatory response to the growing electric utility attention to diversification. What they concluded at that meeting may well constitute the basis for the final rules governing electric company diversification for the next decade.

At the hand of each regulator was the draft report that earlier had been issued by their group — the Ad Hoc Committee on Utility Diversification of the National Association of Regulatory Utility Commissioners. The committee had issued the draft report in April without conclusions or recommendations as a prelude to holding public hearings on issues related to diversification.

Now that the first two days of hearings had been concluded, the five commissioners sat pondering the implications of what they had heard, trying to integrate it with what they already understood about the problems attendant to utility diversification. Theirs was a first effort to crystallize into public policy a set of workable guidelines that could be used by public service commissions across the nation in dealing with the principal issues.

Few active participants

Although the NARUC Ad Hoc Committee on Utility Diversification officially consists of 10 regulators from various states, only seven made it to Madison to participate in public policy discussions. And by the time the committee reconvened at 8 p.m. after adjourning for dinner on the first day of hearings, only five remained. Of these, Stanley York of the Wisconsin Public Service Commission, V. Louise McCarren of the Vermont Public Service Board, and Richard E. Schuler of the New York Public Service Commission, formed the active intellectual core of the group, with the other commissioners present mostly listening and agreeing with final determinations.

Policy issues solidified

At a preliminary meeting of the ad hoc committee held just before the dinner recess, each of five commissioners was given one of the five critical policy issues identified by the committee and asked by the chairman to return later that evening prepared to recommend the adoption of specific proposals. Given the stated need to balance the phrasing of these platform statements so they would be general enough to apply to all state regulatory jurisdictions, on the one hand, yet be specific enough to have teeth at the regional level, on the other hand, the task of formulating such proposals over the competing attention of a Ceasar salad, a couple of pork chops, and the distant clinking of Martini glasses must have been a challenge indeed.

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Foreign Power Briefs

• **A 1.2 million-kW hydroelectric station** will be constructed by Soviet workers in Angola on the Kwanzi River, according to the Yugoslav news agency Tanjug. Angola's foreign trade and planning minister said that he signed documents calling for major Soviet assistance in construction, industry, agriculture and transportation.

• **Spain will continue work** on the Lemoniz nuclear plant in the northern Basque region. Work on the facility was delayed for more than a year because of terrorist threats and attacks. An agreement was recently signed by Iberduero, a Spanish utility, the Basque government, and the central government in Madrid. Iberduero will still have financial control and ownership of the plant, but operating and management control of the plant will be in the hands of the Basque regional government. The $1.5 billion 930,000-kW station is 96 percent complete.

• **A New South Wales, Australia electric utility** has arranged a 15-year multicurrency loan equivalent to $1.25 billion. Eraring Power Company will use the funds to build a power generating complex for the Electricity Commission of New South Wales. The facility will consist of four 660,000-kW generating units. Officials estimate the plant should be complete in 1984. Funds for the loan were provided by 36 international banks.

• **New nuclear technology exchange agreements** were signed by General Electric and Kraftwerk Union. Officials of both companies said the agreement will broaden and expand the information exchange pacts between the two electrical equipment suppliers. They will exchange ideas and information on boiling water reactors, fuel for nuclear power plants and maintenance services for BWR nuclear power plants.

• **World trade in coal will double** in this decade, according to Dr. Irwin M. Stelzer, president of National Economic Research Associates, Inc.. In a recent report, he noted that U.S. exports will double while those of Australia and South Africa will triple by 1990.

• **France** is expected to have an 80 percent nuclear dependency by the end of this decade. The Atomic Industrial Forum reports in its annual survey of commercial nuclear energy use that France has become the first country to make nuclear a primary source of power. In the past seven years France's nuclear growth has risen from 10 percent to 38 percent last year. The AIF also says that the world's total nuclear capacity increased more than 20 percent last year.

• **West Germany's government** has given the OK to a financial plan that would save the fast breeder reactor at Kalkar. After negotiations between West German power utilities and Research Minister Andreas von Bulow, the government decided to let the project be completed. Interim financing for the reactor will come from the Ministry of Finance. The utilities will contribute additional funds to the project if the West German Bundestag(Parliament) approves Kalkar's operating license before September.

• **Engineers at the Oil Institute in Ufa, the capital of the Soviet republic of Bashkiria,** designed a trolleybus airship system. With a propellor at each end, the helium-filled airship flies above a contact wire through which electricity runs the ship's motors. Officials say the airship will be used for carrying people and heavy freight over rough terrain for use in the energy industries. A trolley line for the supply airships can be built for 2 percent of the cost of constructing a road in the remote parts of Siberia.

• **Soviet engineers** are surveying a site for a possible 20,000 MW hydroelectric power station on the Lower Tunguska River in central Siberia. If a dam is built, a reservoir 1,000 km long would be made.

• **Egypt and Canada** have signed a joint statement on nuclear cooperation. The governments of those two countries will explore possibilities of entering into nuclear cooperation and in negotiating a formal agreement.

• **The People's Republic of China** begins a nuclear power program with a 300 MW PWR in the Shanghai area. Sources say that only the reactor may be purchased from abroad.

• **Using their own technology, Argentina** built a small-scale reprocessing plant to allow recycling in thermal reactors, research into breeder technology and entrance into the export market for reprocessed fuel.

• **Japan's Atomic Energy Research Institute** intends to build an experimental multi-purpose High Temperature Gas-Cooled Reactor (HTGR) in 1986. Criticality is expected to be reached sometime in 1991. Using slightly enriched uranium as fuel and helium as coolant, the reactor will have an output of 50 MWt.

• **Brazil's Minister of Mines and Energy, Cesar Cals** has announced his government's plans to build 8, rather than 14, nuclear power stations by the end of the century. Cals cited a sharp reduction in demand for electricity as the main reason for the cutback. The low growth in demand has also caused work on ten hydroelectric and thermal power stations to be postponed or slowed.

• **Westinghouse received an order for more than $33 million from the Egyptian Electric Authority** for a 105,000-kW combustion turbine power plant. In cooperation with Italian and Egyptian firms, Westinghouse will build the facility at El Siouf, near Alexandria. To be fueled by natural gas with petroleum as backup, the plant will serve the baseload needs of the Alexandria area.

CP National buys Warner-Whitney

SAN FRANCISCO — CP National corporation has acquired the Warner-Whitney Group, Inc., of Houston.

Ben W. Agee, chairman and chief executive officer of CP National, announced the acquisition and said, "Due to the forthcoming deregulation of the Bell System Companies in 1983 and the fostering of competition of the telecommunications industry, CP National is committed to rapid expansion in both areas."

The company also announced that it will not go after ownership in Trident Energy Systems, Inc. as previously announced. CP National had intentions of acquiring 30 percent of Trident, a Davis, California solar energy company.

CP National serves over 135,000 retail electric and 336,000 gas and telephone customers in California.

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N.Y. utilities spend $83 million on new research, development

NEW YORK — In an effort to improve production, distribution and conservation of electric energy, New York state investor-owned electric utilities will spend $83 million for research this year.

Details of the plan were released by the Empire State Electric Energy Research Corporation (ESEERCO) as part of the long-range planning document of the New York Power Pool.

ESEERCO's report outlines R&D projects to assist the seven utility members in meeting their goal of providing more reliable, economic and environmentally compatible electric service to customers.

Four projects comprise the major portion of the group's program. Capable of producing 4,800 kilowatts, the first large-scale demonstration of a fuel cell power plant on a U.S. utility system is scheduled to be completed in mid-1982. The plant is located next to Consolidated Edison's East River Generating Station in New York. Nearly $1.3 million has been allocated for the project.

A test program will be used in evaluating the effects of using refuse-derived fuel on Rochester Gas & Electric Corporation's Russell Plant and the environment. Such fuel is now partially replacing coal at the plant.

Two other projects are also underway to improve the use of coal in an environmentally acceptable manner. Researchers are seeking to develop better methods of cleaning coal before it is burned at a test facility in Homer, PA. Nearly $225,000 will be used this year for R&D at the plant, which is owned by New York State Electric & Gas Corporation and Philadelphia Electric Company.

Also, a regenerative flue-gas desulferization project at Niagara Mohawk Power Corporation's Huntley Station is providing researchers with information on ways to reduce wastes created by present desulferization methods. Cost of the Huntley Station project for this year is $3.5 million.

Members of ESEERCO are: Central Hudson Gas & Electic Co.; Consolidated Edison; Long Island Lighting Co.; Niagara Mohawk Power; New York State Electric & Gas Corp.; Orange and Rockland Utilities; and Rochester Gas & Electric Corp..

NARUC supports limited ownership of cogeneration

WASHINGTON, D.C. — The National Association of Regulatory Utility Commissioners has gone on record in support of the current regulation that limits to 50 percent the ownership of cogeneration and small power facilities by utilities.

In testimony before the Senate Energy and Natural Resources Committee's Energy Regulation Subcommittee, Susan M. Shanaman, Chairman of the Pennsylvania Public Utility Commission, said that repeal of the 50 percent limitation rule would encourage electric utilities to invest capital in unregulated subsidiaries at the expense of utility ratepayers.

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Large power companies gained back some lost financial strength in '81

Robert A. Lincicome, Editor-in-Chief

The nation's 100 largest electric utilities posted sizeable revenue, income and per-share earnings gains in 1981, generally overcoming the negative effects of continued inflation, high interest rates and reduced growth in kilowatthour sales. Their performance in 1981 enabled many among the Top 100 to regain some of the financial strength lost over the past several years.

Overall, the gains posted by the Top 100 Electric Utilities were considerably stronger than over the past four years. As might be expected, new record totals for revenues, net income and kilowatthour sales were achieved. Even kWh sales, which gained less than 2 percent in 1981, was a substantially better performer than at any time since 1976.

The achievements of the Top 100 are especially noteworthy in light of continued near-record interest rates, mounting construction costs and sagging demand growth. A year ago we commented that the Top 100 Electric Utilities were "battered by double-digit inflation, undercut by the effects of the recession on industrial load, bled by record high interest rates, frustrated by ever-lengthening construction schedules and victimized by inadequate and unrealistic rate relief." That summation was equally pertinent in 1981, too, except that there was improvement in the rate relief granted during the year. Moreover, skyrocketing fuel costs moderated part way through the year and the effects of subsidiary activities (in non-utility, non-regulated areas) had a positive effect.

The year 1981 cannot be said to have been an easy year, but it proved to be somewhat less-difficult than either 1980 or 1979.

Summary achievements

During 1981, the Top 100 Electric Utilities generated unprecedented revenues of $112.7 billion. This represents an increase of 20.3 percent and reflects the importance of rate relief granted by state public utility commissions. In 1981, kilowatthour sales increased less than 2 percent in the face of recessionary pressures, both direct and indirect, on all classes of customers. Utilities received larger amounts of rate relief in 1980 and early 1981 that fattened revenues despite slow sales growth. Increased collections under fuel adjustment clauses early in the year and improved results from more non-utility, non-regulated activities also contributed to the higher revenues.

Net income for the Top 100 increased even more, reflecting the strong efforts of utility managements to operate more efficiently and economically. Net Income in 1981 rose 22.2 percent, to $10.2 billion. In 1980, Net Income of the Top 100 was $8.35 billion; in 1979, $7.43 billion.

The rate of increase, 22.2 percent, is the highest in a number of years.

One problem with net income growth for the Top 100 Electric Utilities was the increasing role played by Allowance for Funds Used During Construction (AFUDC). AFUDC produces a net addition to income, but only as a paper entry. In large amounts, AFUDC degrades the quality of income and per-share earnings. This is a growing concern, even though the income performance of the Top 100 was markedly better than in 1980.

While the growth of Net Income was high, the effect was mitigated because utilities in 1981 again sold large blocks of common stock to raise needed capital. Despite the increased shares outstanding, per-share earnings improved substantially, for the first time in more than 5 years.

Average per-share earnings were $2.82, up 30 cents per-share from 1980. The increase per average share in 1981 was also three times the cumulative per-share increase from 1977 through 1980. Earlier average per-share earnings were: 1977 — $2.42; 1978 — $2.50; 1979 — $2.51 and 1980 — $2.52.

Kilowatthour sales

Kilowatthour sales moved up slightly in 1981, to 1.84 trillion kWh. This is an increase of 1.7 percent, compared to sales for 1980, which were 1.81 trillion kWh. Going back to 1974, the first full year of post-embargo effects, kWh sales totalled 1.45 trillion. Thus, in the 8 years since the OPEC nations changed the world oil picture, kWh sales by the Top 100 Electric Utilities have increased by 390 billion kWh, 26.9 percent or an average 3.36 percent per year. This is less than half the historic annual kWh sales growth rate prior to 1974.

The low kWh sales growth reflected the negative impact of the recessionary business cycle on commercial and industrial customers, as well as the effect of ever-higher rates on residential usage.

Both residential and commercial sales began the year well, with commercial sales remaining relatively

EARNINGS GROWTH STATISTICS

Company Name	Rank	% Change From 1980	1981 Earnings Per Share
San Diego Gas & Electric	1	131.68	$2.34
Nevada Power	2	118.99	$3.46
Savannah Electric & Power	3	95.90	$2.39
Puget Sound Power & Light	4	78.12	$2.85
Florida Power	5	68.67	$2.80
Central Vermont Public Service	6	63.32	$3.74
Tucson Electric Power	7	60.34	$3.80
Ohio Edison	8	51.32	$2.30
Missouri Public Service	9	50.89	$2.55
Kentucky Utilities	10	43.71	$2.17
Rochester Gas & Electric	11	43.63	$2.93
Washington Water Power	12	41.20	$3.29
Southern California Edison	13	40.86	$4.93
Consolidated Edison	14	37.90	$6.44
Dayton Power & Light	15	35.68	$2.51
Montana-Dakota Utilities	16	31.96	$2.89
Iowa-Illinois Gas & Electric	17	28.26	$3.46
Toledo Edison	18	27.73	$3.27
Public Service of New Mexico	19	25.89	$4.23
Niagara Mohawk Power	20	25.67	$2.35
Portland General Electric	21	25.12	$2.54
Eastern Utilities Associates	22	24.54	$2.03
Wisconsin Electric Power	23	24.36	$4.39
Montana Power	24	23.55	$4.04
Middle South Utilities	25	21.39	$2.44
South Carolina Electric & Gas	26	20.79	$2.44
Northern States Power	27	20.43	$3.89
Pennsylvania Power & Light	28	20.08	$3.17
Central Illinois Light	29	20.00	$2.40
Minnesota Power & Light	30	19.61	$3.05
United Illuminating	31	19.10	$4.24
Arizona Public Service	32	18.55	$3.26
Oklahoma Gas & Electric	33	18.50	$2.05
Interstate Power	34	18.29	$2.07
Allegheny Power Systems	35	16.99	$3.03
New England Electric System	36	15.71	$4.05
Atlantic City Electric	37	15.66	$3.03
Wisconsin Power & Light	38	15.53	$3.05
Detroit Edison	39	15.43	$2.02
Duquesne Light	40	13.19	$2.06
Philadelphia Electric	41	12.50	$2.25
Central Illinois Public Service	42	12.34	$1.73
Carolina Power & Light	43	12.09	$3.06
Cleveland Electric Illuminating	44	11.50	$2.52
Pacific Power & Light	45	11.46	$2.82
Delmarva Power & Light	46	11.25	$1.78
Central Telephone & Utilities	47	10.83	$3.89
Kansas City Power & Light	48	10.78	$4.83
Boston Edison	49	10.67	$4.15
Texas Utilities	50	10.39	$3.51

Company Name	Rank	% Change From 1980	1981 Earnings Per Share
Central Hudson Gas & Electric	51	10.06	$3.72
Gulf States Utilities	52	9.27	$2.24
New York State Electric & Gas	53	9.26	$2.95
El Paso Electric	54	8.78	$3.23
Central Maine Power	55	8.38	$1.81
Florida Power & Light	56	7.87	$4.25
Public Service of Indiana	57	6.54	$3.42
Orange & Rockland Utilities	58	6.33	$2.38
Wisconsin Public Service	59	6.01	$3.00
Hawaiian Electric	60	3.70	$3.92
Central & South West	61	3.67	$2.54
Duke Power	62	3.57	$3.19
Iowa Resources	63	3.51	$3.54
Commonwealth Edison	64	3.03	$3.06
Public Service of Colorado	65	2.60	$1.97
Kansas Power & Light	66	2.48	$3.30
Cincinnati Gas & Electric	67	2.22	$2.30
Potomac Electric Power	68	1.90	$2.14
Baltimore Gas & Electric	69	1.65	$3.70
Consumers Power	70	1.30	$3.12
Long Island Lighting	71	0.79	$2.55
Idaho Power	72	0.33	$3.05
Central Louisiana Electric	73	0.00	$2.46
Houston Lighting & Power	74	0.00	$3.14
American Electric Power	75	-0.84	$2.37
Illinois Power	76	-1.06	$2.84
Northeast Utilities	77	-1.53	$1.29
Southwestern Public Service	78	-2.17	$1.80
Iowa Public Service	79	-2.53	$2.70
Utah Power & Light	80	-2.56	$2.29
General Public Utilities	81	-2.94	$0.33
Southern Indiana & Gas Electric	82	-3.21	$3.32
Teco Energy	83	-3.85	$3.00
Kansas Gas & Electric	84	-4.04	$2.85
Public Service of New Hampshire	85	-4.33	$2.65
Iowa Electric Light & Power	86	-4.83	$1.97
Sierra Pacific Power	87	-5.13	$1.48
Pacific Gas & Electric	88	-5.28	$3.41
Northern Indiana Public Service	89	-6.80	$1.37
Louisville Gas & Electric	90	-6.87	$2.71
Virginia Electric & Power	91	-8.29	$1.77
Union Electric	92	-9.52	$1.90
Empire District Electric	93	-15.82	$1.33
Public Service Electric & Gas	94	-15.97	$2.63
Southern Company	95	-18.83	$1.81
Indianapolis Power & Light	96	-23.64	$2.81
Madison Gas & Electric	97	-24.89	$1.86
Texas-New Mexico Power	98	-25.31	$2.39
Commonwealth Energy System	99	-26.26	$2.22
Otter Tail Power	100	-32.02	$1.72

SALES DATA

Company	Rank	1981 Total Sales (KWH) % Increase	Average Annual Growth 1976 – 1981	1981 Sales (KWH) By Type of Customer (% of Sales) Resid.	Comm.	Ind.	Other	Average Annual Residential Use 1981	1980	Ratio of Long Term Debt to Net Plant 1981	1980
Allegheny Power Systems	1	26.58	3.92	19.8	10.7	35.9	33.6	8,788	8,718	46.0	47.1
Central Hudson Gas & Electric	2	16.25	4.91	21.1	18.5	21.8	38.6	6,268	6,379	71.6	68.0
Sierra Pacific Power	3	13.12	5.34	28.6	36.0	19.5	15.9	7,302	7,539	43.0	4.4
Arizona Public Service	4	12.72	4.73	28.4	29.3	19.5	22.9	10,247	9,995	45.6	47.1
Central Vermont Public Service	5	10.44	2.77	37.2	8.5	34.0	20.3	7,866	7,704	59.9	54.4
Portland General Electric	6	10.33	3.11	34.9	26.1	24.1	14.9	12,181	12,918	53.2	57.1
Ohio Edison	7	10.13	1.13	27.4	19.9	37.6	14.9	7,760	7,870	45.5	46.4
Nevada Power	8	10.01	4.55	43.9	3.2	48.0	6.1	14,527	14,248	46.9	42.1
Tucson Electric Power	9	10.01	10.14	18.9	16.7	29.2	36.2	7,694	7,614	46.7	48.1
Washington Water Power	10	9.97	0.31	30.8	18.8	28.1	22.3	14,697	15,130	52.4	55.5
Interstate Power	11	9.63	3.72	20.7	15.6	46.9	16.9	6,790	7,114	52.1	52.0
Public Service of New Mexico	12	6.84	10.05	19.2	25.7	14.9	40.2	5,697	5,782	44.7	42.8
Pacific Gas & Electric	13	5.79	0.61	31.7	30.4	26.6	11.3	5,569	5,606	44.4	45.1
Montana-Dakota Utilities	14	5.60	5.25	42.2	27.1	26.7	4.0	7,463	7,413	45.3	49.7
Texas-New Mexico Power	15	5.27	6.10	27.6	19.4	50.7	2.3	10,244	10,842	40.3	44.6
Central Maine Power	16	4.87	3.19	36.8	23.2	35.6	4.0	8,777	8,982	51.1	44.6
Pacific Power & Light	17	4.68	2.99	28.1	21.0	27.9	23.0	12,091	12,609	54.3	52.3
Puget Sound Power & Light	18	4.38	2.43	47.2	22.7	16.0	14.2	14,626	15,489	48.2	47.1
Southern California Edison	19	4.23	2.32	26.7	29.5	30.9	12.8	5,879	5,939	47.5	47.1
Houston Lighting & Power	20	3.79	6.83	22.7	17.4	50.7	9.1	13,590	14,219	40.2	40.4
San Diego Gas & Electric	21	3.66	3.21	35.9	34.1	24.2	5.8	5,471	5,666	40.5	46.0
Idaho Power	22	3.50	1.14	25.4	28.4	27.4	18.9	14,054	14,446	47.0	48.8
Florida Power & Light	23	3.48	5.60	49.6	33.7	7.5	9.3	11,216	11,473	41.9	40.8
Florida Power	24	3.45	5.39	39.8	19.2	16.9	24.1	10,758	10,643	46.6	47.8
Duquesne Light	25	2.50	1.25	21.0	29.8	48.3	0.9	5,698	5,770	49.3	47.6
New York State Electric & Gas	26	2.41	1.08	40.2	22.8	25.8	11.1	7,393	7,289	42.8	40.7
Duke Power	27	2.36	2.83	25.9	18.2	38.6	17.3	12,392	12,560	42.3	43.8
Tex. Energy	28	2.35	4.04	34.5	21.2	38.2	6.1	12,708	12,384	39.9	41.5
Philadelphia Electric	29	2.34	1.03	28.4	11.0	52.8	7.9	6,899	7,058	46.1	45.8
Baltimore Gas & Electric	30	2.07	3.36	34.2	17.1	48.8	0.0	7,948	7,956	47.3	48.8
Pennsylvania Power & Light	31	2.05	2.10	35.2	25.7	34.7	4.4	9,157	9,205	48.0	46.4
Central & South West	32	1.93	6.09	24.0	18.8	30.2	27.0	9,894	10,332	41.0	38.7
Southern Company	33	1.90	3.01	25.7	18.8	37.6	17.8	10,645	11,027	55.1	54.2
Public Service of Colorado	34	1.84	5.56	26.9	36.3	26.9	9.8	5,734	5,937	41.4	43.7
Cincinnati Gas & Electric	35	1.84	3.36	34.6	23.0	31.6	10.8	9,592	9,994	48.2	48.2
Wisconsin Public Service	36	1.70	3.66	27.1	22.8	31.2	19.1	7,172	7,187	41.6	47.2
Northern States Power	37	1.68	2.81	26.9	13.2	39.6	20.3	7,136	7,256	38.0	37.2
Virginia Electric & Power	38	1.68	3.01	33.6	24.8	16.1	25.7	10,948	11,056	62.6	61.7
Savannah Electric & Power	39	1.49	2.01	36.0	26.3	34.2	3.4	10,340	10,433	54.2	47.4
American Electric Power	40	1.35	4.01	19.7	12.1	32.0	36.1	10,092	10,120	54.8	54.3
Boston Edison	41	1.31	2.12	21.6	39.9	15.7	22.8	5,190	5,378	45.0	41.0
Potomac Electric Power	42	1.28	3.09	24.2	41.4	25.2	9.2	8,790	8,971	44.6	47.8
Oklahoma Gas & Electric	43	1.21	6.21	25.2	16.3	22.1	36.4	10,515	11,520	43.6	45.9
Dayton Power & Light	44	1.15	2.06	35.1	19.6	30.1	15.2	9,591	10,042	83.1	84.9
Hawaiian Electric	45	1.10	2.55	28.6	22.0	48.4	1.0	7,173	7,335	40.7	42.0
Niagara Mohawk Power	46	0.93	0.49	25.7	28.6	35.4	10.3	6,914	6,843	44.8	47.6
Montana Power	47	0.86	2.93	19.8	18.2	27.9	34.1	7,977	8,055	50.3	43.0
Atlantic City Electric	48	0.74	4.16	43.7	32.6	22.5	1.2	7,923	8,003	42.7	44.9
Carolina Power & Light	49	0.68	3.37	25.4	16.8	32.7	25.3	12,087	12,568	46.4	43.1
Consumers Power	50	0.65	0.48	30.9	24.2	40.5	4.4	6,642	6,812	40.3	46.1
Gulf States Utilities	51	0.55	6.36	20.6	15.0	54.2	10.2	12,786	13,173	47.5	46.5
General Public Utilities	52	0.55	2.24	33.4	24.8	36.0	5.7	7,560	7,726	53.3	54.9
Southwestern Public Service	53	0.47	4.34	14.4	16.1	43.5	26.0	7,148	7,601	46.1	47.9
Northern Indiana Public Service	54	0.42	0.59	16.7	3.6	71.7	8.0	6,720	7,026	49.6	48.2
Iowa-Illinois Gas & Electric	55	0.40	3.54	22.8	27.2	44.9	5.1	5,996	6,488	39.9	38.7
Wisconsin Electric Power	56	0.36	1.96	29.6	24.2	34.5	11.7	7,149	7,314	45.5	46.9
Minnesota Power & Light	57	0.35	10.38	8.7	7.6	66.8	17.8	7,878	7,692	46.0	47.0
Northeast Utilities	58	-0.05	1.42	36.2	29.2	25.7	8.8	7,548	7,664	48.3	51.5
Texas Utilities	59	-0.22	8.39	32.0	26.4	30.8	10.8	11,862	13,125	40.9	41.7
Indianapolis Power & Light	60	-0.39	2.29	31.4	26.3	42.1	1.2	9,328	9,821	42.4	39.0
Southern Carolina Electric & Gas	61	-0.40	2.89	31.5	23.7	35.4	9.4	12,183	12,580	44.2	46.1
Iowa Electric Light & Power	62	-0.51	3.14	34.6	25.6	30.7	9.1	7,894	8,275	44.6	46.7
New England Electric System	63	-0.51	0.58	35.0	29.5	24.8	10.7	6,025	6,241	43.8	45.4
Public Service of Indiana	64	-0.57	4.34	25.9	18.7	31.9	23.5	10,329	10,812	39.8	38.4
Detroit Edison	65	-0.65	-0.62	29.8	18.6	45.5	6.2	6,243	6,408	47.1	48.8
Otter Tail Power	66	-0.78	5.04	29.8	15.6	35.1	19.5	9,190	9,235	39.8	42.1
El Paso Electric	67	-0.78	2.20	26.1	28.0	19.0	26.9	5,849	6,066	31.3	32.0
Public Service Electric & Gas	68	-0.78	1.58	28.0	36.5	33.0	1.4	5,261	5,443	44.3	44.8
Delmarva Power & Light	69	-0.87	2.40	27.0	22.4	33.2	17.4	7,967	8,337	48.9	48.1
Consolidated Edison	70	-1.23	-0.95	25.5	5.2	57.8	11.5	3,231	3,340	42.5	45.3
Long Island Lighting	71	-1.31	2.16	41.7	0.0	48.5	9.8	6,815	6,956	49.2	47.5
Eastern Utilities Associates	72	-1.50	1.45	26.3	24.7	19.7	29.3	5,449	5,626	54.2	51.7
Kentucky Utilities	73	-1.56	-0.07	29.9	17.8	17.8	34.4	10,334	10,692	48.2	47.3
Commonwealth Edison	74	-1.59	1.33	27.9	30.9	30.6	10.6	6,291	6,625	47.7	47.8
Rochester Gas & Electric	75	-1.79	2.72	26.2	21.7	24.7	27.4	6,754	6,744	46.6	46.0
Illinois Power	76	-1.89	3.99	26.3	17.2	46.1	10.3	8,011	8,541	39.1	44.2
Union Electric	77	-2.08	3.22	31.9	28.9	32.0	7.1	8,955	9,848	47.3	46.2
Utah Power & Light	78	-2.35	4.95	20.6	15.7	39.4	24.2	7,821	7,693	46.8	46.0
Louisville Gas & Electric	79	-2.44	2.35	31.3	24.2	34.6	10.0	8,581	9,589	40.5	41.5
Public Service of New Hampshire	80	-2.50	3.87	29.5	10.2	30.1	30.2	8,948	9,176	39.1	38.1
Central Louisiana Electric	81	-2.62	5.55	37.3	15.6	40.5	6.6	11,288	11,404	49.9	56.9
Southern Indiana Gas & Electric	82	-3.07	5.39	21.5	16.2	32.2	30.1	10,081	10,860	48.5	37.6
Toledo Edison	83	-3.20	0.46	26.8	18.1	43.1	12.0	7,966	8,232	45.6	46.9
Kansas City Power & Light	84	-3.20	3.11	28.2	39.1	28.0	4.7	7,700	8,923	45.6	43.2
Orange & Rockland	85	-3.31	0.40	31.6	21.4	29.0	18.0	5,926	6,094	41.3	46.0
United Illuminating	86	-3.55	0.96	33.4	34.1	28.8	1.6	6,312	6,546	41.3	46.3
Cleveland Electric Illuminating	87	-3.60	0.10	25.0	23.9	47.3	3.8	6,807	6,885	44.4	45.2
Missouri Public Service	88	-3.71	2.01	38.4	25.2	18.9	17.5	7,857	8,224	51.9	49.7
Iowa Public Service	89	-3.80	5.21	33.4	23.9	31.7	11.0	6,919	7,435	50.8	47.7
Middle South Utilities	90	-3.84	8.68	29.2	17.7	44.7	8.4	11,347	11,888	60.6	61.1
Kansas Power & Light	91	-4.12	3.63	25.2	28.7	22.8	23.3	7,545	8,635	38.2	42.3
Iowa Resources	92	-4.16	3.18	38.8	24.8	33.8	2.5	7,988	8,783	39.9	42.0
Commonwealth Energy System	93	-4.27	-1.97	22.3	17.2	12.9	47.7	5,491	5,604	43.6	44.2
Central Illinois Public Service	94	-4.36	2.58	25.5	10.5	39.2	24.9	8,090	8,789	41.0	43.5
Wisconsin Power & Light	95	-4.36	5.47	29.3	16.1	28.6	25.9	7,805	8,002	45.2	42.1
Central Illinois Light	96	-4.71	3.43	29.8	39.2	28.1	2.1	9,437	9,128	36.0	34.5
Kansas Gas & Electric	97	-4.73	6.43	36.2	19.7	38.3	5.8	9,433	10,708	49.7	42.4
Central Telephone & Utilities	98	-7.20	4.38	25.6	26.1	21.5	27.5	6,481	6,956	45.3	48.7
Empire District Electric	99	-8.27	3.37	31.5	20.0	29.9	18.5	8,543	9,500	48.9	48.4
Madison Gas & Electric	100	-12.71	7.33	28.6	43.3	6.0	22.1	6,033	6,120	38.1	40.2

strong throughout the year except for one month. Residential sales weakened early in the year, recovered in the late Spring, slipped into a decline in the Fall and only recovered marginally at year-end.

Industrial sales lost ground early in the year, recovered in the late Spring and Summer, then went into a decline again through the end of the year.

Average residential customer use of electricity declined in 1981, for only the third time since *EL&P* launched its annual Top 100 Electric Utilities report program in 1966. The decline, 303 kWh, or 3.5 percent, is the biggest decline recorded. In total, 1981 average residential use was 8463 kWh, less than that posted back in 1977.

TABLE I
THE TOP 10 IN KWH SALES

Rank '81	Rank '80	Company	KWH Sales (millions)	'81% Change
1	1	American Electric Power	113,011	1.35
2	2	Southern Company	94,217	1.90
3	4	Southern California Edison	62,451	4.23
4	6	Pacific Gas & Electric	61,669	5.79
5	3	Commonwealth Edison	61,229	–1.59
6	5	Texas Utilities	58,372	–0.22
7	8	Houston Lighting & Power	56,880	3.79
8	9	Duke Power	53,548	2.36
9	7	Middle South Utilities	53,035	–3.84
10	10	Central & South West	47,850	1.93

Companies posting the highest average residential kWh use were, generally, located in the Pacific Northwest, where electric energy historically has been cheap, and in the Southeast. Leaders in 1981 were: 1. Washington Water Power, 14,697 kWh (-2.9 percent); 2. Puget Sound Power & Light, 14,266 kWh (-7.9 percent); 3. Nevada Power, 14,527 (2.0 percent); 4. Idaho Power, 14,054 kWh (-2.7 percent); and 5. Houston Lighting & Power, 13,590 kWh (-4.4 percent.

Overall, 57 companies reported kWh sales gains for 1981. This reflects a 23 percent decline for 1980 and down 30 percent from 1979. Aside from a half-dozen individual performances, 1981 gains tended to be smaller also. Forty-three utilities recorded negative growth in 1981, which ties 1981 with 1975 as the second worst sales-growth year in the past 17.

Table I reflects the relative standings of the ten companies reporting the largest kWh sales in the industry.

Revenues up

Total revenues reported by the Top 100 Electric Utilities in 1981 were $112.7 billion, compared to $93.7 billion in 1980. This represents a 20.8 percent gain, largest in recent years, and largely reflects the effect of rate increases granted by regulatory commissions in 1980 and early in 1981. The increase also reflects the positive results of subsidiary non-utility, non-regulated operations.

There were fewer large revenue gainers in 1981 than in 1980: 26 with increases above 20.0 percent and 54 between 10.0 and 19.9 percent in 1981, versus 47 above 20 percent and 44 between 10.0 and 19.9 percent a year earlier. However, the 1981 gains tended to be larger overall than a year previous.

The largest revenue gain was 54.7 percent, posted by Hawaiian Elec-

tric, followed by Allegheny Power System's 38.6 percent increase, and Central Hudson ahead 35.6 percent.

For several years we have listed the members of the Billion Dollar Club — utilities that received revenues of at least a billion dollars. The list now has reached 40 utilities and has become too long to publish. The list of companies recording $2 billion in revenues is shown as Table II.

Net income

Total net income of the Top 100 Electric Utilities rose 22.16 percent, to a record $10.2 billion. A year earlier, net income of $8.35 billion was reported by the Top 100. This is the largest increase in net income to be recorded in many years and reflects the rate relief granted by Commissions and utility managements' concerted efforts to control expenses.

TABLE II
LARGEST ELECTRIC UTILITY REVENUE PRODUCERS
(more than $2-million in revenues)

Rank '81	Rank '80	Company	Revenues (billions)	'81% Change
1	1	Pacific Gas & Electric	$6.195	17.8
2	2	Consolidated Edison	$4.866	23.3
3	3	Southern Company	$4.256	13.1
4	4	American Electric Power	$4.193	11.8
5	5	Southern California Edison	$4.055	10.7
6	6	Commonwealth Edison	$3.737	12.4
7	7	Public Service Electric & Gas	$3.472	16.0
8	8	Florida Power & Light	$3.089	31.6
9	9	Middle South Utilities	$2.772	18.3
10	12	Houston Lighting & Power	$2.769	30.4
11	11	Texas Utilities	$2.738	25.9
12	10	Consumers Power	$2.734	18.7
13	13	Philadelphia Electric	$2.433	14.6
14	29	Union Electric	$2.162	2.6
15	17	Niagara Mohawk Power	$2.151	21.0
16	32	General Public Utilities	$2.065	12.8
17	18	Central & South West	$2.055	18.7
18	16	Detroit Edison	$2.054	13.3

Twenty-two additional companies posted revenues between $1-billion and $2-billion.

As mentioned earlier, the effect of Allowances for Funds Used During Construction is a concern to utility managements, security analysts and investors in that it leads to an overstatement of *real* income. AFUDC is a paper transaction that inflates net income, as contrasted to inclusion of Construction Work in Progress in the rate base, which results in real money income. Where AFUDC remains a small portion of net income, little difficulty is caused. However, when AFUDC represents the majority of net income, the picture is different.

With large construction programs continuing, although on a declining basis, and with interest rates at high levels, the AFUDC problem is a very real one. The Top 100 utilities did perform better in 1981 than in 1980, but the quality of that income is not what it should be.

Overall, 88 utilities reported net income gains for 1981 compared to 74 a year ago. Median net income change for the Top 100 was 22.6 percent in 1981, more than double that for the Top 100 in 1980 — 10.5 percent.

Shareholder earnings improve

Per-share earnings performance of

FINANCIAL STATISTICS

Company	Net Income Rank	Net Income % Gain	Revenue Rank	Revenue % Gain	Sales (KWH) Rank	Sales (KWH) % Gain	Int. Cov. Ratio 1981	Int. Cov. Ratio 1980	Earnings Per Share 1981	Price/Share 1981 (Dollars) High	Price/Share 1981 (Dollars) Low	% Change Long Term Debt 1981
San Diego Gas & Electric	1	165.8	25	20.7	21	3.7	1.24	0.58	$2.34	14.000	11.000	–0.69
Nevada Power	2	134.8	76	10.6	8	10.0	2.18	1.66	$3.46	22.875	18.250	33.34
Puget Sound Power & Light	3	117.5	55	14.1	18	4.4	1.58	1.06	$2.85	14.000	12.250	22.44
Savannah Electric & Power	4	109.8	73	11.0	39	1.5	1.21	0.77	$2.39	12.875	8.875	31.30
Florida Power	5	90.6	5	31.8	24	3.5	2.20	1.82	$2.80	16.375	12.375	12.25
Washington Water Power	6	67.1	64	9.4	10	10.0	1.90	1.49	$3.29	18.375	15.625	14.96
Central Vermont Public Service	7	67.1	10	29.3	5	10.4	3.66	2.21	$3.74	17.750	12.750	17.95
Kentucky Utilities	8	66.8	40	17.4	73	–1.6	1.31	1.16	$2.17	17.000	14.375	10.33
Southern California Edison	9	64.5	74	10.7	19	4.2	1.86	1.16	$4.93	30.625	22.875	15.40
Public Service of New Mexico	10	64.4	28	19.8	12	6.6	2.41	2.28	$4.23	24.875	19.250	24.73
Ohio Edison	11	61.6	35	18.4	7	10.1	0.90	0.86	$2.30	13.500	11.000	10.37
Tucson Electric Power	12	61.3	83	9.5	9	10.0	3.10	2.84	$3.80	18.875	13.375	3.02
Dayton Power & Light	13	58.5	27	19.9	44	1.2	2.14	1.65	$2.51	14.875	12.000	16.08
Pennsylvania Power & Light	14	52.2	12	28.0	31	2.0	1.03	1.08	$3.17	18.375	14.750	19.52
Missouri Public Service	15	51.6	88	8.6	88	–3.7	1.76	1.65	$2.55	11.500	9.000	11.61
Rochester Gas & Electric	16	50.6	20	22.1	75	–1.8	2.17	1.56	$2.93	15.000	11.750	9.92
United Illuminating	17	47.7	18	23.9	86	–3.5	2.27	1.16	$4.24	20.750	17.750	2.70
Arizona Public Service	18	44.3	50	15.2	4	12.7	1.93	2.30	$3.26	19.625	15.125	11.71
Middle South Utilities	19	43.7	36	18.3	90	–3.8	1.09	0.88	$2.44	13.875	11.000	14.86
Toledo Edison	20	43.2	80	10.1	83	–3.2	1.88	1.53	$3.27	18.375	15.125	7.06
Montana-Dakota Utilities	21	42.5	11	29.2	14	5.6	3.02	2.24	$2.89	23.250	16.250	–6.63
El Paso Electric	22	41.4	31	18.9	67	–0.8	4.90	5.92	$2.23	11.000	9.875	24.80
Montana Power	23	41.0	87	8.8	47	0.9	2.01	1.56	$4.04	36.375	24.500	39.15
Iowa-Illinois Gas & Electric	24	40.8	71	11.4	55	0.4	2.24	2.33	$3.45	18.375	15.125	19.40
Niagara Mohawk Power	25	39.9	24	21.0	46	0.9	1.67	1.47	$2.35	13.750	10.750	2.68
Consolidated Edison	26	39.0	19	23.3	70	–1.2	3.71	2.72	$6.44	33.625	22.625	–2.75
Eastern Utilities Associates	27	38.3	21	21.8	72	–1.5	1.31	0.73	$2.03	12.500	10.250	15.85
Portland General Electric	28	36.3	23	21.3	6	10.3	1.25	1.14	$2.54	14.500	11.000	1.39
South Carolina Electric & Gas	29	35.2	26	20.4	61	–0.4	2.21	1.87	$2.44	16.000	12.500	4.71
Wisconsin Electric Power	30	31.1	52	14.4	56	0.4	2.68	2.36	$4.39	29.250	20.375	–0.54
Gulf States Utilities	31	30.6	22	21.5	51	0.5	1.39	1.92	$2.24	12.750	10.500	15.63
Central Hudson Gas & Electric	32	29.2	3	35.6	2	16.3	1.90	1.77	$3.72	19.000	16.000	5.03
Detroit Edison	33	28.5	60	13.3	65	–0.6	0.89	0.97	$2.02	12.750	10.875	12.39
Public Service of Indiana	34	28.2	70	11.5	64	–0.6	3.20	3.16	$3.42	22.500	18.250	22.69
Philadelphia Electric	35	27.9	51	14.6	29	2.3	1.90	1.88	$2.25	14.375	11.125	15.76
Allegheny Power System	36	27.7	2	38.6	1	26.6	2.31	1.74	$3.03	17.250	13.000	1.40
Central Illinois Light	37	27.3	75	10.7	96	–4.7	3.02	2.51	$2.40	15.625	12.250	–6.81
Houston Lighting & Power	38	27.0	8	30.4	20	3.8	3.05	2.98	$3.14	21.750	16.625	14.12
Carolina Power & Light	39	27.0	17	24.9	49	0.7	1.82	1.74	$3.06	20.750	16.750	12.60
Central Maine Power	40	26.9	90	7.9	16	4.9	1.39	1.53	$1.81	13.250	11.375	26.78
Central Louisiana Electric	41	26.8	37	18.2	81	–2.6	1.19	1.30	$2.46	14.625	12.750	–3.85
Public Service of New Hampshire	42	26.6	15	25.5	80	–2.5	1.64	3.21	$2.65	16.500	14.125	7.26
Minnesota Power & Light	43	26.2	69	11.7	57	0.3	2.48	1.78	$3.05	19.250	15.000	–3.20
Oklahoma Gas & Electric	44	25.8	44	16.5	43	1.2	2.19	1.91	$2.05	14.500	12.000	–1.70
Pacific Power & Light	45	23.9	4	32.1	17	4.7	1.04	1.05	$2.82	21.875	16.000	9.32
Central Illinois Public	46	23.7	85	5.4	94	–4.4	3.82	3.51	$1.73	12.125	10.000	–1.88
Cleveland Electric Illuminating	47	23.7	59	13.4	87	–3.6	1.41	1.36	$2.52	16.500	13.630	9.65
Duquesne Light	48	23.4	48	15.6	25	2.5	1.51	1.58	$2.06	14.125	11.375	10.89
Kansas Gas & Electric	49	22.8	92	6.6	97	–4.7	2.93	2.21	$2.85	16.500	13.760	34.47
New York State Electric & Gas	50	22.6	30	18.9	26	2.4	2.09	1.84	$2.96	16.250	13.875	4.57
Commonwealth Edison	51	22.5	67	12.4	74	–1.6	0.67	0.68	$3.06	22.375	17.750	10.49
Atlantic City Electric	52	21.9	7	31.1	48	0.7	2.76	2.97	$3.03	18.250	15.250	10.16
Interstate Power	53	21.2	53	14.3	11	9.6	2.32	1.78	$2.07	13.875	11.000	–0.08
Texas Utilities	54	20.7	14	25.9	59	–0.2	2.49	2.24	$3.51	22.125	16.250	7.36
Long Island Lighting	55	20.6	9	30.4	71	–1.3	2.16	1.58	$2.55	15.750	13.875	19.74
Public Service of Colorado	56	20.1	47	15.6	34	1.8	2.65	2.32	$1.97	15.000	12.750	3.09
New England Electric System	57	19.2	39	17.6	63	–0.5	1.98	1.97	$4.05	26.875	18.875	5.14
Wisconsin Power & Light	58	18.7	66	12.5	95	–4.4	2.98	2.92	$3.05	21.500	15.500	15.61
Northern States Power	59	17.3	77	10.5	37	1.7	3.07	3.08	$3.89	27.000	20.000	7.39
Iowa Resources	60	16.2	79	10.2	92	–4.2	1.28	1.98	$3.54	23.375	19.375	5.01
Kansas City Power & Light	61	16.2	94	5.8	84	–3.2	2.67	2.83	$4.83	24.750	19.500	12.69
Delmarva Power & Light	62	16.1	41	16.9	69	–0.9	1.73	1.25	$1.78	12.750	10.500	4.65
Florida Power & Light	63	16.1	6	31.6	23	3.5	1.52	1.72	$4.25	32.000	23.875	13.39
Illinois Power	64	13.8	85	9.2	76	–1.9	2.22	2.31	$2.84	21.375	16.625	–1.99
Hawaiian Electric	65	13.8	1	54.7	45	1.1	1.64	1.87	$3.92	26.750	20.500	0.34
Kansas Power & Light	66	13.4	93	6.4	91	–4.1	3.57	3.67	$3.30	20.000	16.125	4.31
Boston Edison	67	13.2	34	18.4	41	1.3	1.71	2.01	$4.15	24.500	19.500	–2.36
Sierra Pacific Power	68	13.0	49	15.3	3	13.1	1.26	1.23	$1.48	13.250	10.125	19.75
Cincinnati Gas & Electric	69	12.5	61	13.2	35	1.8	1.46	1.51	$2.30	17.375	14.000	10.62
Central Telephone & Utilities	70	12.2	89	8.3	98	–7.2	3.41	3.21	$3.89	35.750	23.500	0.61
Central & South West	71	10.5	32	18.7	32	1.9	2.98	3.23	$2.54	15.375	12.000	10.15
Duke Power	72	10.2	58	13.6	27	2.4	2.11	2.21	$3.19	22.500	15.875	–1.86
Northern Indiana Public Service	73	10.2	57	13.9	54	0.4	1.55	1.77	$1.37	12.375	10.125	7.59
Southwestern Public Service	74	9.8	63	12.8	53	0.5	2.56	2.73	$1.80	13.125	10.500	9.54
Iowa Electric Light & Power	75	9.4	78	10.2	62	–0.5	1.34	1.55	$1.97	14.250	11.125	10.49
Idaho Power	76	9.4	54	14.1	22	3.5	1.13	1.21	$3.05	22.500	19.000	4.43
Orange & Rockland	77	9.1	56	14.0	85	–3.3	2.19	2.21	$2.35	14.625	11.625	–4.72
Consumers Power	78	8.6	33	18.7	50	0.6	0.87	0.97	$3.12	19.250	15.875	–2.78
Wisconsin Public Service	79	8.5	64	12.8	36	1.7	3.51	3.84	$3.00	20.500	14.750	–2.86
Utah Power & Light	80	7.9	86	9.0	78	–2.3	2.17	2.41	$2.29	20.000	15.000	19.62
Northeast Utilities	81	7.2	16	25.0	58	0.0	0.85	1.05	$1.29	9.750	8.000	3.38
American Electric Power	82	6.8	68	11.8	40	1.3	1.24	1.26	$2.37	18.375	15.375	5.97
Louisville Gas & Electric	83	6.4	72	11.3	79	–2.4	2.32	2.61	$2.71	18.875	16.000	10.07
Potomac Electric Power	84	5.1	43	16.9	42	1.3	2.16	2.45	$2.14	15.500	11.875	0.49
Baltimore Gas & Electric	85	5.1	46	15.9	30	2.1	2.57	2.64	$3.70	25.375	19.750	2.74
Pacific Gas & Electric	86	3.7	38	17.8	13	5.8	1.58	1.69	$3.41	24.125	19.500	6.37
Union Electric	87	2.0	97	2.6	77	–2.1	1.30	1.87	$1.90	11.875	9.875	16.27
Iowa Public Service	88	0.5	42	16.9	89	–3.8	1.80	1.81	$2.70	20.000	17.250	12.28
General Public Utilities	89	–0.2	65	12.8	52	0.5	0.21	0.17	$0.33	6.875	3.875	0.54
Teco Energy	90	–0.5	29	19.2	28	2.4	2.63	3.28	$3.00	22.750	16.500	3.82
Virginia Electric & Power	91	–2.0	98	2.0	38	1.7	1.05	1.19	$1.77	13.125	10.125	9.45
Southern Indiana Gas & Electric	92	–2.4	91	7.1	82	–3.1	3.13	4.42	$3.32	20.000	16.125	34.16
Southern Company	93	–5.3	62	13.1	33	1.9	1.18	1.29	$1.81	12.875	10.875	10.28
Public Service Electric & Gas	94	–9.7	45	16.0	68	–0.8	1.92	2.17	$2.63	20.125	16.500	3.94
Empire District Electric	95	–13.3	96	4.5	99	–8.3	1.49	1.86	$1.33	11.500	9.750	0.00
Texas-New Mexico Power	96	–14.7	13	27.3	15	5.3	0.00	0.00	$2.39	18.750	15.500	3.39
Indianapolis Power & Light	97	–19.4	98	0.8	60	–0.4	1.93	2.77	$2.81	23.875	18.000	17.82
Otter Tail Power	98	–22.7	82	9.9	66	–0.8	1.00	1.44	$1.72	19.250	15.625	0.96
Madison Gas & Electric	99	–23.0	100	0.2	100	–12.7	2.65	3.60	$1.66	15.750	12.000	–1.56
Commonwealth Energy System	100	–24.2	81	9.9	93	–4.3	1.78	2.54	$2.22	16.875	12.375	9.18

ALPHABETICAL LISTING OF COMPANY PERFORMANCES

Company	Electric Sales Rank	Electric Sales KWH Sales (millions)	Customers Served Electric Total (1,000's)	Electric % Gain	Customers Served Gas Total (1,000's)	Gas % Gain	Revenues Total ($1,000's)	Revenues % Electric	Revenues % Gas	Net Income After Tax ($1,000's)
Allegheny Power Systems	12	44,586	1,137	1.21	0	0.00	$1,607,461	100.00	0.00	$132,477
American Electric Power	1	113,011	2,511	0.92	69	2.45	$4,192,645	97.06	2.02	$362,279
Arizona Public Service	44	13,388	439	4.04	341	0.28	$ 882,154	82.84	17.16	$170,048
Atlantic City Electric	76	5,675	366	1.32	0	0.00	$ 469,683	100.00	0.00	$ 39,457
Baltimore Gas & Electric	33	17,584	848	1.35	512	0.38	$1,421,056	65.74	32.93	$123,243
Boston Edison	48	12,024	611	1.35	0	0.00	$1,049,596	93.26	0.00	$ 58,462
Carolina Power & Light	17	30,487	758	2.14	0	0.00	$1,343,558	100.00	0.00	$160,937
Central & South West	10	47,850	1,381	3.27	0	0.00	$2,056,318	100.00	0.00	$204,496
Central Hudson Gas & Electric	77	5,522	213	1.25	45	2.69	$ 444,881	89.55	10.45	$ 25,553
Central Illinois Light	80	4,727	186	0.03	184	0.53	$ 436,971	63.85	36.15	$ 27,959
Central Illinois Public Service	59	8,380	305	0.68	148	1.94	$ 529,391	80.73	19.27	$ 51,927
Central Louisiana Electric	81	4,700	180	2.77	0	0.00	$ 260,642	98.40	0.00	$ 23,043
Central Maine Power	71	6,348	389	1.57	0	0.00	$ 365,378	98.99	0.00	$ 26,195
Central Telephone & Utilities	94	2,803	132	1.03	0	0.00	$ 138,701	99.30	0.00	$ 10,051
Central Vermont Public Service	98	2,112	114	2.47	0	0.00	$ 117,339	98.33	0.00	$ 11,367
Cincinnati Gas & Electric	41	14,786	597	0.91	367	0.39	$1,081,473	63.16	36.84	$ 77,825
Cleveland Electric Illuminating	34	17,508	711	0.11	0	0.00	$1,012,930	98.80	0.00	$120,817
Commonwealth Edison	5	61,229	2,967	0.63	0	0.00	$3,737,311	100.00	0.00	$351,803
Commonwealth Energy System	78	5,304	279	4.29	199	2.00	$ 563,455	64.10	33.20	$ 17,359
Consolidated Edison	18	30,302	2,739	0.58	1,017	-0.65	$4,865,934	81.73	11.24	$407,438
Consumers Power	23	25,684	1,339	0.82	1,159	1.85	$2,733,973	51.19	46.26	$181,404
Dayton Power & Light	55	10,288	420	0.25	265	0.39	$ 779,586	70.46	28.61	$ 74,755
Delmarva Power & Light	64	7,395	286	3.62	74	1.33	$ 608,504	82.85	13.65	$ 45,893
Detroit Edison	14	34,013	1,767	0.17	0	0.00	$2,054,057	97.91	0.00	$176,787
Duke Power	8	53,548	1,307	1.74	0	0.00	$1,927,822	86.72	0.00	$278,356
Duquesne Light	43	13,630	556	0.57	0	0.00	$ 796,847	98.64	0.00	$ 85,895
Eastern Utilities Associates	83	4,268	228	0.89	0	0.00	$ 297,931	96.96	0.00	$ 12,437
El Paso Electric	90	3,699	186	3.02	0	0.00	$ 250,379	99.59	0.00	$ 49,579
Empire District Electric	96	2,318	100	1.48	0	0.00	$ 91,858	99.61	0.00	$ 5,775
Florida Power & Light	11	46,263	2,336	3.93	0	0.00	$3,088,620	98.27	0.00	$188,586
Florida Power	30	19,457	824	3.66	0	0.00	$1,278,297	97.10	0.00	$ 95,070
General Public Utilities	16	32,012	1,598	1.24	0	0.00	$2,065,487	99.85	0.00	$ 20,544
Gulf States Utilities	21	27,810	517	3.35	86	0.52	$1,221,714	90.57	3.08	$120,550
Hawaiian Electric	72	6,201	286	1.22	0	0.00	$ 665,151	99.90	0.00	$ 25,976
Houston Lighting & Power	7	56,880	1,118	7.99	0	0.00	$2,769,215	100.00	0.00	$225,200
Idaho Power	49	11,861	257	1.66	0	0.00	$ 299,706	100.00	0.00	$ 41,875
Illinois Power	42	14,213	525	0.82	383	0.43	$ 964,292	64.40	35.60	$107,516
Indianapolis Power & Light	57	8,777	332	1.63	0	0.00	$ 336,584	93.79	0.00	$ 39,187
Interstate Power	87	4,048	155	0.61	45	1.43	$ 259,970	71.09	28.91	$ 16,506
Iowa Electric Light & Power	88	3,969	204	0.48	131	0.95	$ 345,590	63.57	34.50	$ 19,463
Iowa-Illinois Gas & Electric	86	4,063	173	0.59	222	0.19	$ 416,796	45.42	54.58	$ 37,571
Iowa Resources	85	4,170	231	0.29	133	0.19	$ 328,261	67.06	32.36	$ 31,126
Iowa Public Service	92	3,124	159	0.45	122	0.75	$ 325,793	61.62	38.28	$ 25,679
Kansas City Power & Light	60	8,319	349	1.33	0	0.00	$ 471,711	98.75	0.00	$ 65,397
Kansas Gas & Electric	63	7,468	233	1.93	0	0.00	$ 313,093	99.65	0.00	$ 53,060
Kansas Power & Light	65	7,276	278	1.06	133	1.38	$ 410,090	74.03	25.97	$ 48,869
Kentucky Utilities	53	10,603	364	1.46	0	0.00	$ 438,291	99.53	0.00	$ 29,952
Long Island Lighting	45	13,387	908	0.88	396	0.86	$1,664,832	84.26	15.74	$198,902
Louisville Gas & Electric	62	7,600	296	0.47	233	0.21	$ 494,932	63.99	35.81	$ 34,738
Madison Gas & Electric	99	1,961	89	1.98	68	2.27	$ 162,082	57.28	42.30	$ 9,542
Middle South Utilities	9	53,035	1,570	1.52	241	-0.08	$2,771,788	93.18	5.02	$281,483
Minnesota Power & Light	58	8,593	115	5.03	9	-1.11	$ 369,259	97.02	2.50	$ 34,921
Missouri Public Service	95	2,397	134	1.00	40	-0.49	$ 166,311	82.03	17.48	$ 14,091
Montana-Dakota Utilities	100	1,642	111	3.22	170	3.23	$ 288,495	28.57	50.53	$ 21,650
Montana Power	61	7,797	229	1.48	103	-0.37	$ 490,239	42.84	31.10	$ 53,662
Nevada Power	74	5,814	199	5.32	0	0.00	$ 244,674	100.00	0.00	$ 29,148
New England Electric System	36	16,582	1,072	1.54	0	0.00	$1,282,102	98.50	0.00	$ 90,983
New York State Electric & Gas	51	11,016	670	0.92	129	1.16	$ 767,539	79.37	20.63	$ 90,265
Niagara Mohawk Power	15	32,890	1,361	0.07	428	1.18	$2,150,718	79.97	20.03	$186,358
Northeast Utilities	29	20,587	1,080	1.10	152	1.16	$1,666,057	88.01	10.95	$ 95,118
Northern Indiana Public Service	46	12,997	361	-0.25	527	0.96	$1,556,255	45.75	54.25	$ 60,658
Northern States Power	22	25,784	1,100	1.43	276	2.28	$1,280,889	77.92	21.23	$114,037
Ohio Edison	24	24,662	963	0.58	0	0.00	$1,279,649	100.00	0.00	$163,892
Oklahoma Gas & Electric	28	21,343	591	2.84	0	0.00	$ 826,117	100.00	0.00	$ 67,129
Orange & Rockland	91	3,462	209	1.65	88	1.97	$ 425,099	73.92	25.73	$ 30,372
Otter Tail Power	93	2,840	120	1.45	0	0.00	$ 118,104	100.00	0.00	$ 8,267
Pacific Gas & Electric	4	61,669	3,515	1.95	2,897	1.38	$6,194,575	63.05	33.10	$430,907
Pacific Power & Light	26	24,083	652	1.34	0	0.00	$1,268,553	55.10	0.00	$137,176
Pennsylvania Power & Light	27	22,954	1,007	0.70	0	0.00	$1,133,278	99.37	0.00	$183,182
Philadelphia Electric	20	28,268	1,324	0.77	293	3.26	$2,433,425	82.27	14.65	$223,761
Portland General Electric	39	15,307	502	2.31	0	0.00	$ 594,789	98.16	0.00	$ 98,968
Potomac Electric Power	35	16,769	522	2.95	0	0.00	$1,000,510	99.61	0.00	$ 93,297
Public Service of Colorado	37	15,473	846	3.12	701	3.04	$1,336,171	55.54	43.59	$ 84,094
Public Service of Indiana	31	18,790	541	0.87	0	0.00	$ 720,126	99.20	0.00	$129,028
Public Service of New Hampshire	73	6,075	290	0.13	0	0.00	$ 440,884	98.90	0.00	$ 58,018
Public Service of New Mexico	75	5,761	218	2.09	0	0.00	$ 338,165	98.16	0.00	$ 88,095
Public Service Electric & Gas	19	29,961	1,694	0.20	1,310	0.22	$3,471,652	66.89	33.11	$212,599
Puget Sound Power & Light	38	15,413	562	3.09	0	0.00	$ 408,747	100.00	0.00	$ 84,048
Rochester Gas & Electric	70	6,686	290	1.62	228	6.94	$ 613,541	61.06	34.64	$ 65,750
San Diego Gas & Electric	54	10,402	792	2.52	514	1.92	$1,159,662	81.70	18.19	$ 91,438
Savannah Electric & Power	97	2,293	90	1.89	0	0.00	$ 135,618	99.78	0.00	$ 8,900
Sierra Pacific Power	89	3,773	174	2.72	53	1.76	$ 269,784	81.40	13.71	$ 18,787
South Carolina Electric & Gas	50	11,763	351	1.74	169	1.70	$ 759,687	74.91	24.77	$ 68,622
Southern California Edison	3	62,451	3,233	2.17	1	1.25	$4,055,087	99.98	0.01	$422,024
Southern Company	2	94,217	2,620	2.11	0	0.00	$4,256,237	99.32	0.00	$325,979
Southern Indiana Gas & Electric	84	4,254	104	1.26	53	1.11	$ 220,260	71.90	26.08	$ 17,819
Southwestern Public Service	47	12,369	305	2.83	0	0.00	$ 546,595	99.62	0.00	$ 55,147
Teco Energy	52	10,830	339	3.64	0	0.00	$ 641,452	96.72	0.00	$ 47,592
Texas-New Mexico Power	79	5,287	170	4.10	0	0.00	$ 275,439	100.00	0.00	$ 5,136
Texas Utilities	6	58,372	1,630	4.57	0	0.00	$2,738,377	99.60	0.00	$369,398
Toledo Edison	66	7,151	269	0.59	5	3.50	$ 442,284	98.32	1.06	$ 70,402
Tucson Electric Power	68	7,106	198	3.83	0	0.00	$ 350,468	99.50	0.00	$ 82,613
Union Electric	25	24,279	987	1.00	108	1.05	$1,105,536	92.23	6.59	$127,605
United Illuminating	82	4,548	283	0.74	0	0.00	$ 451,022	99.60	0.00	$ 37,187
Utah Power & Light	40	15,065	465	7.83	0	0.00	$ 663,989	99.88	0.00	$ 92,408
Virginia Electric & Power	13	38,906	1,381	2.82	121	1.08	$2,161,853	95.74	4.26	$180,614
Washington Water Power	56	9,610	228	2.77	76	1.89	$ 317,661	60.17	38.09	$ 39,474
Wisconsin Electric Power	32	17,792	813	0.81	216	1.53	$1,152,383	75.49	23.70	$ 90,415
Wisconsin Power & Light	67	7,121	304	1.17	102	2.15	$ 454,516	73.98	25.35	$ 35,538
Wisconsin Public Service	69	6,795	266	2.02	152	1.32	$ 492,262	59.83	40.17	$ 32,436

the Top 100 Electric Utilities improved in 1981 and was substantially better than in 1980. Gainers outnumbered losers. Average earnings per-share jumped markedly and the bulk of companies that in 1981 suffered continuing or repetitive annual declines recovered in 1981.

In 1981, 72 utilities enjoyed gains in per-share earnings from 1980, while 26 reported declines. In 1980, as in 1979, 56 companies posted gains and 42 companies suffered declines.

For the 99 companies that reported earnings results in 1981, the average increase per-share was 30 cents, an increase of 11.9 percent from 1980 and three-times the cumulative increase (10 cents) from 1977 through 1980.

TABLE III
THE TOP 10 INCOME PRODUCERS
(Net After-Tax Available for Common)

Rank '81	Rank '80	Company	Income (millions)	'81% Change
1	1	Pacific Gas & Electric	$430.9	3.7
2	7	Southern California Edison	$422.0	64.5
3	5	Consolidated Edison	$407.4	39.0
4	2	American Electric Power	$368.3	6.8
5	4	Texas Utilities	$359.4	20.7
6	6	Commonwealth Edison	$351.8	22.5
7	3	Southern Company	$326.0	-6.3
8	10	Middle South Utilities	$281.5	43.7
9	8	Duke Power	$278.4	10.2
10	13	Houston Lighting & Power	$225.2	27.0

The arithmetic average change in per-share earnings in 1981 was 14.72 percent, compared with 3.70 percent in 1980 and 2.45 in 1979.

The median rate of change, 10.38, also was well above the median for 1980 — 2.85 percent — and for 1979 — 1.97 percent.

As in previous reports, the companies recording the largest per-share earnings gains were recovering from a bad year previous. So it was in 1981. Eight of the first 25 in 1981 were in the bottom 25 in 1980, ten ranked 51-75 in 1980, four ranked between 26 and 50 and two were repeaters in the first 25 from a year ago. One (Montana-Dakota Utilities) was unranked (not in the Top 100 in 1980).

Another indication of the improved financial performance is that the majority of companies that had suffered repeated years of earnings problems reversed their situations in 1981. Kentucky Utilities, which had suffered earnings declines in four of the last five years, rebounded into 10th place with a gain of 43.71 percent. Only General Public Utilities, still burdened with both units of the Three Mile Island nuclear plant down, and clean up costs for TMI-2 increasing, suffered a fourth consecutive year of earnings decline.

Return on equity

At the end of 1981, the average return on equity *allowed* was 15.14 percent, up from 13.88 for 1980. Unfortunately, average return on equity *earned* in 1981 was 12.65 percent, as compared to 11.33 percent in 1980.

Thus, the spread between *allowed return on equity and earned* return on equity narrowed slightly. But earned returns in 1981 still fell shy of allowed return in 1980 by nearly 10 percent and at 12.65 percent, remained 16.7 percent below the level allowed for 1981.